# ALGONQUIN POWER & UTILITIES CORP.

# ANNUAL INFORMATION FORM

March 14, 2016

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*All information contained in this Annual Information Form (“**AIF**”) is presented as at March 14, 2016, unless otherwise specified. In this AIF, all dollar figures are in Canadian dollars, unless otherwise indicated.*

## Caution concerning forward-looking statements

Certain statements included in this AIF contains forward-looking information within the meaning of applicable securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. All forward-looking information is given pursuant to the "safe harbour" provisions of applicable securities legislation. The words "anticipates", "believes", "budget", "could", "estimates", "expects", "forecasts", "intends", "may", "might", "plans", "projects", "schedule", "should", "will", "would" and similar expressions are often intended to identify forward-looking information, although not all forward-looking information contains these identifying words. The forward-looking information reflects management's current beliefs and is based on information currently available to the Corporation's management.

Forward-looking information is included throughout this AIF, including among other places, under the heading "General Development of the Business", "Description of the Business" and "Legal Proceedings and Regulatory Actions". These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances.

Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. The Corporation (as defined in this AIF) cautions that although it believes that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. The forward-looking information is subject to risks, uncertainties and other factors that could cause actual results to differ materially from historical results or results anticipated by the forward-looking information. Factors which could cause results or events to differ from current expectations include, but are not limited to: derivative financial instruments, including, but not limited to, hedging availability; commodity price and availability risk; foreign exchange risk; interest rate risk; commercial relationship risk; credit risk; labour risk; weather risk; regulatory risk; environmental risk; capital market risk, including, but not limited to, economic conditions, cost of financing, capital resources and liquidity risk; construction and development risks; inability to complete the Acquisition (as defined in this AIF); an increase in the cash purchase price of the Acquisition; uncertainty regarding the length of time required to complete the Acquisition; the anticipated benefits of the Acquisition may not materialize or may not occur within the time periods anticipated by the Corporation; impact of significant demands placed on the Corporation as a result of the Acquisition; failure by the Corporation to repay the Final Instalment (as defined in this AIF); failure to repay the non-revolving credit facilities in favor of Algonquin in an aggregate amount of US$1.6 billion (the "Acquisition Credit Facilities"); potential unavailability of the Acquisition Credit Facilities; alternate sources of funding that would be used to replace the Acquisition Credit Facilities may not be available when needed; lack of control by the Corporation of Empire District Electric Company ("Empire") and its subsidiaries prior to the closing of the Acquisition; impact of the Acquisition related expenses; accuracy and completeness of Empire's publicly disclosed information; increased indebtedness of Algonquin after the closing of the Acquisition; the Acquisition and related financing, including the Offering (as defined in this AIF), could result in a downgrade of credit ratings of the Corporation, Empire and/or their subsidiaries; historical and pro forma combined financial information may not be representative of future performance; potential undisclosed liabilities of Empire and its subsidiaries; ability to retain key personnel of Empire following the Acquisition; operating and maintenance risks; risks associated with changes in economic conditions; developments in technology could reduce demand for electricity, gas and water; changes in customer energy usage patterns; risk of failure of information technology infrastructure and cybersecurity; disruption of fuel supply; natural disasters or other catastrophic events; impairment testing of certain long-lived assets could result in impairment charges; indebtedness of Empire; risks relating to the Instalment Receipts, the Debentures and the Common Shares (each as as defined in this AIF); unanticipated maintenance and other expenditures; risk associated with the continuation, renewal, replacement and/or regulatory approval of power supply and capacity purchase contracts; risks associated with pension plan performance and funding requirements; regulatory and government decisions including, but not limited to, changes to environmental, financial reporting and tax legislation and regulations; risk of loss of licences and permits; risk of loss of service area; market energy sales prices; changes to the regulation of rates Empire charges its utility customers; risk of condemnation; and adverse publicity and reputational risk.

Material risk factors include those set out in this AIF under "Enterprise Risk Management". Readers are cautioned that such risks and uncertainties may cause APUC's actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Given these risks, undue reliance should not be placed on these forward-looking statements. In addition, such statements are made based on information available and expectations as of the date of this AIF and such expectations may change after this date. APUC is not obligated to nor does it intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

## Non-GAAP Financial Measures

The terms "adjusted net earnings", "adjusted earnings before interest, taxes, depreciation and amortization" ("**Adjusted EBITDA**"), "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales", are used throughout this AIF. The terms "adjusted net earnings", "per share cash provided by operating activities", "adjusted funds from operations", "per share cash provided by adjusted funds from operations", Adjusted EBITDA, "net energy sales" and "net utility sales" are not recognized measures under GAAP. There is no standardized measure of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales", and "net utility sales" consequently APUC's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "adjusted net earnings", Adjusted EBITDA, "adjusted funds from operations", "per share cash provided by adjusted funds from operations", "per share cash provided by operating activities", "net energy sales" and "net utility sales" can be found throughout this AIF. Per share cash provided by operating activities is not a substitute measure of performance for earnings per share. Amounts represented by per share cash provided by operating activities do not represent amounts available for distribution to shareholders and should be considered in light of various charges and claims against APUC. A calculation and analysis of Adjusted EBITDA and "adjusted funds from operations", "adjusted net earnings", "net energy sales", and "net utility sales" can be found in APUC's most recent management's discussion and analysis ("MD&A") for the year ended December 31, 2015, which calculation and analysis is incorporated herein by reference.

## Use of Non-GAAP Financial Measures

Adjusted EBITDA

EBITDA is a non-GAAP measure used by many investors to compare companies on the basis of ability to generate cash from operations. APUC uses these calculations to monitor the amount of cash generated by APUC as compared to the amount of dividends paid by APUC. APUC uses Adjusted EBITDA to assess the operating performance of APUC without the effects of (as applicable): depreciation and amortization expense, income tax expense or recoveries, acquisition costs, litigation expenses, interest expense, gain or loss on derivative financial instruments, write down of intangibles and property, plant and equipment, earnings attributable to non-controlling interests and gain or loss on foreign exchange, earnings or loss from discontinued operations and other typically non-recurring items. APUC adjusts for these factors as they may be non-cash, unusual in nature and are not factors used by management for evaluating the operating performance of the Corporation. APUC believes that presentation of this measure will enhance an investor's understanding of APUC's operating performance. Adjusted EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

Adjusted net earnings

Adjusted net earnings is a non-GAAP measure used by many investors to compare net earnings from operations without the effects of certain volatile primarily non-cash items that generally have no current economic impact or items such as acquisition expenses or litigation expenses and are viewed as not directly related to a company's operating performance. Net earnings of APUC can be impacted positively or negatively by gains and losses on derivative financial instruments, including foreign exchange forward contracts, interest rate swaps and energy forward purchase contracts as well as to movements in foreign exchange rates on foreign currency denominated debt and working capital balances. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted net earnings to assess its performance without the effects of (as applicable): gains or losses on foreign exchange, foreign exchange forward contracts, interest rate swaps, acquisition costs, litigation expenses and write down of intangibles and property, plant and equipment, earnings or loss from discontinued operations and other typically non-recurring items as these are not reflective of the performance of the underlying business of APUC. APUC believes that analysis and presentation of net earnings or loss on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of net earnings or loss determined in accordance with GAAP.

Adjusted funds from operations

Adjusted funds from operations is a non-GAAP measure used by investors to compare cash flows from operating activities without the effects of certain volatile items that generally have no current economic impact or items such as acquisition expenses and are viewed as not directly related to a company's operating performance. Cash flows from operating activities of APUC can be impacted positively or negatively by changes in working capital balances, acquisition expenses, litigation expenses and cash provided by or used in discontinued operations. Adjusted weighted average shares outstanding represents weighted average shares outstanding adjusted to remove the dilution effect related to shares issued in advance of funding requirements. APUC uses adjusted funds from operations to assess its performance without the effects of (as applicable) changes in working capital balances, acquisition expenses, litigation expenses, cash provided by or used in discontinued operations and other typically non-recurring items affecting cash from operations as these are not reflective of the long-term performance of the underlying businesses of APUC. APUC believes that analysis and presentation of funds from operations on this basis will enhance an investor's understanding of the operating performance of its businesses. It is not intended to be representative of cash flows from operating activities as determined in accordance with GAAP.

Net energy sales

Net energy sales is a non-GAAP measure used by investors to identify revenue after commodity costs used to generate revenue where revenue generally is increased or decreased in response to increases or decreases in the cost of the commodity to produce that revenue. APUC uses net energy sales to assess its revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through either directly or indirectly in the revenue that is charged. APUC believes that analysis and presentation of net energy sales on this basis will enhance an investor's understanding of the revenue generation of its businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

Net utility sales

Net utility sales is a non-GAAP measure used by investors to identify utility revenue after commodity costs, either natural gas or electricity, where these commodities are generally included as a pass through in rates to its utility customers. APUC uses net utility sales to assess its utility revenues without the effects of fluctuating commodity costs as such costs are predominantly passed through and paid for by the utility customer. APUC believes that analysis and presentation of net utility sales on this basis will enhance an investor's understanding of the revenue generation of its utility businesses. It is not intended to be representative of revenue as determined in accordance with GAAP.

# 1. CORPORATE STRUCTURE

## 1.1 Name, Address and Incorporation

Algonquin Power & Utilities Corp. ("APUC" or the "Corporation") was originally incorporated under the Canada Business Corporations Act on August 1, 1988 as Traduction Militech Translation Inc. Pursuant to articles of amendment dated August 20, 1990 and January 24, 2007, the Corporation amended its articles to change its name to Société Hydrogenique Incorporée – Hydrogenics Corporation and Hydrogenics Corporation – Corporation Hydrogenique, respectively. Pursuant to a certificate and articles of arrangement dated October 27, 2009, the Corporation, among other things, created a new class of common shares (the "Common Shares"), transferred its existing operations to a newly formed independent corporation, exchanged new Common Shares for all of the trust units of Algonquin Power Co. (**"APCo"**) (the "**Unit Exchange Transaction**") and changed its name to Algonquin Power & Utilities Corp (**"APUC"**). The head and principal office of APUC is located at Suite 100, 354 Davis Road, Oakville, Ontario, L6J 2X1.

Unless the context indicates otherwise, references in this AIF to "**APUC**" or the "**Company**" include, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiary entities. Such use of "**APUC**" or the "**Corporation**" to refer to these other legal entities and partnership interests does not constitute a waiver by APUC or such entities or partnerships of their separate legal status for any purpose.

## 1.2 Intercorporate Relationships

### 1.2.1 Subsidiaries

The subsidiaries of APUC are grouped by the primary business operations of the Corporation consisting of: the Generation Business Group ("**Generation Group**"), the Distribution Business Group ("**Distribution Group**") and the Transmission Business Group ("**Transmission Group**"). The principal holding for APUC's Generation Group is an investment in 100% of the issued and outstanding trust units of APCo. The principal holding for both APUC's Distribution Group and its Transmission Group is an investment in 100% of the issued and outstanding common shares of Liberty Utilities (Canada) Corp. ("**LU Canada**"), a Canadian federal corporation, which owns all of the issued and outstanding common shares of Liberty Utilities (America) Co., a Delaware corporation, which owns all of the issued and outstanding common shares of Liberty Utilities (America) Holdco Inc., a Delaware corporation, which owns all of the membership interests in Liberty Utilities (America) Holdings LLC, a Delaware LLC, which owns all of the issued and outstanding shares of Liberty Utilities Co. ("**Liberty Utilities**"), a Delaware corporation, which owns the utility subsidiaries as well as the U.S. based transmission subsidiaries. The Transmission Group's U.S. based assets are held by Liberty Utilities (Pipeline & Transmission) Corp., a Delaware corporation which is 100% owned by Liberty Utilities Co. . The Transmission Group's Canadian assets are held by Algonquin Power (Ontario Transmission) Inc., which is 100% owned by LU Canada. The ownership chains for each of the three primary business operations of the Corporationare described below.

In regard to the Generation Group, the subsidiaries of APCo include the ownership chains of Algonquin Power Trust ("**APT**") and Algonquin Power (Canada) Holdings Inc. ("**APCH**"), APCo directly owns a 100% interest in Windlectric Inc. ("Windlectric"), a Canadian federal corporation that is developing various wind projects including one in Saskatchewan and one in Ontario, and APCo owns 100% of the issued and outstanding shares of Cornwall Solar Inc. ("Corwall Solar", which owns a solar power facility in Cornwall, Ontario (the "Cornwall Solar Project"). APT's subsidiaries include the ownership chain of Algonquin Power Operating Trust ("**APOT**"), and APCH's subsidiaries include the ownership chain of Algonquin Power Fund (America) Inc. ("**APFA**"). In regard to the Distribution Group, Liberty Utilities has direct investments in electric distribution, natural gas distribution, and water distribution utility systems in California, Iowa, Illinois, Missouri, Montana, Arkansas, Georgia, Massachusetts and New Hampshire. Also, Liberty Utilities Co, through its subsidiary, Liberty Utilities Sub Corp. ("Liberty SubCo"), has investments in water distribution and wastewater collection utility systems in Arizona, Illinois, Missouri, and Texas. In regard to the Transmission Group, Liberty Utilities (Pipeline & Transmission) Corp. has a direct ownership in the Market Path Project and Supply Path Project (each as defined in this AIF) with Kinder Morgan, Inc. ("Kinder Morgan")and Algonquin Power (Ontario Transmission) Inc. is undertaking the development of a transmission project in Ontario.

The following chart summarizes the major lines of business.

**SHAREHOLDERS**

**ALGONQUIN POWER & UTILITIES CORP.**

| GENERATION BUSINESS GROUP | DISTRIBUTION BUSINESS GROUP | TRANSMISSION BUSINESS GROUP |
|---|---|---|
| RENEWABLE - CDN HYDRO, WIND AND SOLAR | ELECTRIC UTILITIES | |
| RENEWABLE - US HYDRO, WIND AND SOLAR | NATURAL GAS UTILITIES | NATURAL GAS PIPELINE |
| THERMAL - CDN | WATER & WASTEWATER UTILITIES | ELECTRIC TRANSMISSION |
| THERMAL - US | | |

The major chains are described below, including details on the legal entities that comprise these chains and the facilities they own. Additional information on the facilities is described in Schedules A, B, C, D, and E.

### (i) Generation Business Group

### Generation Business Group Chain Entities

APCo is the sole beneficiary of APT. APCo also owns 100% of the Class A common shares of APCH, an Ontario corporation. All of the Class B common shares of APCH are owned by 2496838 Ontario Inc., an indirect subsidiary of APOT, and all of the Class C common shares of APCH are owned by St. Leon Wind Energy GP Inc. ("St. Leon GP"), another indirect APOT subsidiary. APCo also owns 100% of the issued and outstanding shares of Cornwall Solar, which owns the Cornwall Solar Projectin Cornwall, Ontario and APCo directly owns a 100% ownership in Windlectric, a Canadian federal corporation that is developing various wind projects including one in Saskatchewan and one in Ontario. APCo is also the sole owner of eleven Ontario numbered companies which hold various rights to a pipeline of pending solar projects in Ontario.

### APT Group

APT forms part of the APCo business unit. APT is an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. APT owns all of the trust units of APOT.

APT controls the entities that own some of the Canadian hydroelectric facilities. APT owns all of the trust units in KMS Power Income Fund, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997 in accordance with the laws of the Province of Alberta. APT directly owns a 2% limited partnership interest in the Algonquin Power (Mont-Laurier) Limited Partnership (the "Mont-Laurier Partnership"), a Québec limited partnership, which owns the Mont-Laurier hydroelectric facility (the "Mont-Laurier Hydro Facility" )and the Côte Ste.-Catherine hydroelectric generating facility ( the "Côte Ste.-Catherine Hydro Facility" ), while APCH owns the remaining 98% partnership interests, comprised of an 86.5% limited partnership interest and an 11.5% general partnership interest.

APT directly owns the Hydraska hydroelectrical generating facility (the "Hydraska Hydro Facility" ) and the Arthurville hydroelectrical generatingfacility (the "Arthurville Hydro Facility" ), and owns both the limited partnership interests in and the general partner of Algonquin Power (Campbellford) Limited Partnership, an Ontario limited partnership which operates a 4 megawatt hydroelectric generating facility on the Trent River near Campbellford, Ontario (the "**Campbellford Hydro Facility**").

APT also controls the entities which own APUC's interests in two wind projects in Quebec. APT owns a 24.995% interest in Éoliennes Belle-Rivières, sociètè en commandite ("**Val-Éo Partnership**") which owns the 125 MW project located in the local municipality of Saint-Gideon de Grandmont ( the "Val-Éo Wind Project"). A non-APUC relatedentity, Val-Éo Coop de solidarité, owns 74.995% of the Val-Éo Partnership. The remaining 0.01% interest in the Val-Éo Partnership is owned by a Quebec company, Éoliennes Belle-Rivières Inc., the general partner. The interests in Éoliennes Belle-Rivières Inc. are owned 75% by Val-Éo Coop de solidarité, and 25% by APT. APT indirectly owns and controls 50% of Saint-Damase Wind Energy Fleur de Lis General Partner Corporation ("**Saint-Damase GP**") which owns the Saint-Damase Wind Project. The remaining 50% is owned by Corporation Municipal de Saint- Damase, a non-APUC related entity, which also owns 100% of the preferred shares issued by Saint-Damase GP.

## APOT Group

APOT is an unincorporated open ended trust created by a trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. APOT is governed by a Second Amended and Restated Trust Indenture, effective December 8, 2014.

APOT controls the entities that own the 104 MW wind facility located at St. Leon, Manitoba (the "St. Leon Wind Facility"). The APOT entity that owns the St. Leon Wind Facility is St. Leon Wind Energy LP, a Manitoba limited partnership ("**St. Leon LP**"). St. Leon LP is owned by its general partner, St. Leon GP , by St. Leon Wind Energy Trust, a Manitoba trust ("**St. Leon Trust**") and by AirSource Power Fund I LP, a Manitoba limited partnership ("**AirSource**"). St. Leon LP has also issued 100 Class B limited partnership units which were acquired by APUC on January 1, 2013 in exchange for newly issued APUC Series C preferred shares ("Series C Share"). St. Leon Trust is owned 100% by AirSource, the limited partner of which is Algonquin (AirSource) Power LP ("**AAP LP**") which holds a 99.99% limited partnership interest in the limited partnership, and which in turn is owned 99.99% by APOT as limited partner. APOT also controls the general partner of AAP LP, Algonquin (AirSource) GP Inc., an Ontario corporation which holds the remaining 0.01% general partnership interest. AirSource is also the 100% owner of St. Leon GP. St. Leon GP is a Canadian corporation and St. Leon Trust is a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba. The AirSource and AAP LP limited partnerships were formed in Manitoba and Ontario, respectively. St. Leon LP also owns 100% of 2496838 Ontario Inc., an Ontario corporation.

St. Leon LP directly owns a 99% limited partnership interest in St. Leon II Wind Energy LP ("**St. Leon II LP**"), a Manitoba partnership which owns the 16.5 MW wind facility (the "**St. Leon II Wind Facility**"), an expansion of the St. Leon Wind Facility, located at St. Leon Manitoba. St. Leon LP also wholly owns St. Leon II Wind Energy GP Inc., a Manitoba corporation which owns the remaining 1% general partnership interest in St. Leon II LP.

APOT is the sole limited partner, holding a 99% limited partnership interest, in Red Lily Wind Power II Limited Partnership ("**Red Lily II LP**"), a Saskatchewan limited partnership. The general partner of Red Lily II LP is Red Lily Wind Power II GP Inc., a Saskatchewan corporation, which is also owned by APOT and owns the remaining 1% general partnership interest.

APOT has two ownership interests in Alberta. It is the beneficial owner of one hydroelectric facility in Alberta (the "**Dickson Dam Hydro Facility**"). APOT also owns 50% of Valley Power Corp., an Ontario corporation, which holds a 0.001% limited partnership interest partner in Valley Power LP, an Alberta limited partnership which owns the Alberta biomass facility and APOT directly holds a 49.9995% limited partnership interest in Valley Power LP.

## APCH Group

APCH, a subsidiary of APCo, is an Ontario corporation which controls the entities that own the majority of APUC's hydroelectric generating facilities in Canada. APCH owns Algonquin Power (America) Inc., a Delaware corporation, which is the parent company of APCo's operations in the United States.

In Ontario, APCH directly owns the Hurdman hydroelectrical generating facility (the "Hurdman Hydro Facility" ) . In Québec, Algonquin Power Fund (Canada) Inc. ("APFC") directly owns the hydro facilities known as Hydro Snemo, St. Raphael, Belleterre, and St. Brigette, in addition to owning 100% of the beneficial interests in the Rawdon and St. Alban hydroelectrical facilities (the "Rawdon Hydro Facility" and "St. Alban Hydro Facility" respectively) . APCH also holds a direct interest in Société Hydro-Donnacona ("S.E.N.C."), the owner of the Donnacona hydroelectrical facility (the "Donnacona Hydro Facility" ) . S.E.N.C. is a Québec general partnership, and is owned 99.99% by APCH and 0.01% by Donnacona Holdings Inc., an Ontario corporation 100% owned by APFC. APCH also owns a 99.99% interest in Société en Commandité Chute Ford, a Quebec limited partnership which owns the Glenford hydroelectric facility and APCH 100% owns Glenford Minority Inc., an Ontario Corporation, which is the general partner, holding a 0.01% interest in Société en Commandité Chute Ford.

APCH owns a 99% interest in Algonquin Power (Morse) LP, an Ontario limited partnership, which owns the Morse Wind Facility in Saskatchewan. AirSource Power Fund GP Inc., a Canada corporation wholly owned by APOT holds the remaining 1% general partnership interest. APCH also owns 1631667 Alberta ULC, an Alberta unlimited liability corporation.

APCH also owns Algonquin Power Corporation Inc. ("**APCI**"), an Ontario corporation. APCI owns a 99.9% general partnership interest in Algonquin Power (Long Sault) Partnership (the "**LS Partnership**"), an Ontario general partnership which is a 50% partner in the Long Sault Rahpids hydroelectrical facility (the "Long Sault Hydro Facility" ) with the remaining 50% being held by non-Algonquin interests. APCH has an agreement in place which allows it to buy an ownership interest in the parties which own the remaining 50% of the Long Sault Hydro Facility. APCI is also the sole owner ofAlgonquin Power (Long Sault) Corporation Inc., an Ontario corporation which is the other general partner, holding the remaining 0.1% general partnership interest, in the LS Partnership.

Together, APCH and APCo own and control several entities set up for future solar developments in Ontario. Algonquin Power (Paris Solar) LP is 99% owned by APCH as limited partner; the remaining 1% is owned by 7985452 Canada Ltd., a wholly owned subsidiary of APCo which acts as the general partner. Algonquin Power (Minden Solar) LP is 99% owned by APCo as limited partner; the remaining 1% is owned by Algonquin Power (Minden Solar) GP Inc., a wholly owned subsidiary of APCH which acts as the general partner. Algonquin Power (Brantford Solar) LP is 99% owned by APCH as limited partner; the remaining 1% is owned by 7906404 Canada Ltd., a wholly owned subsidiary of APCo which also acts as the general partner. Algonquin Power (Centreville Solar) Inc., an Ontario corporation, is 100% owned by APCo. APCo also wholly owns 7985517 Canada Ltd. and 7813589 Canada Ltd.

## APFA Group

APFA, a Delaware corporation, is owned by APA (which owns 100% of APFA's common shares) and by APA's parent APCH (which owns 100% of the APFA's Series A Preferred shares). APFA owns or holds interests in the hydroelectric, thermal cogeneration, and wind entities and facilities in the U.S.

APFA owns Algonquin Power Sanger LLC, (**"Sanger LLC"**) a California limited liability company, and Algonquin Power Windsor Locks LLC ("Windsor LLC", a Connecticut limited liability company. These entities respectively own the U.S. Sanger and Windsor Locks Thermal Facilities. Sanger LLC directly owns 100% of Dyna Fibers Inc., a California corporation that operates a hydro-mulch business at the Sanger facility site. APFA also owns KMS Crossroads, LLC, a Delaware limited liability corporation.

APFA owns Algonquin Tinker Gen Co. (**"Tinker Gen Co."**) and Algonquin Northern Maine Gen Co. (**"Northern Maine Gen Co."**), both being Wisconsin companies. Tinker Gen Co. is also registered in New Brunswick, and Northern Maine Gen Co. is also registered in Maine. Tinker Gen Co. operates the 38.9MW of electrical generating assets in New Brunswick, and Northern Maine Gen Co. is the owner of the Millinocket and Caribou storage dams and the Squa Pan hydroelectrical facility (the "Squa Pan Hydro Facility") . APFA is also the sole owner of Algonquin Energy Services Inc., a Delaware corporation that is also registered in Connecticut, District of Columbia, Maine, Maryland and Ohio. AES contractually provides the electrical energy requirements for commercial and industrial customers in northern Maine.

APFA owns 100% of the interests in Algonquin Power (Gearbox Holdings), LLC, a Delaware LLC, which owns a 99% equity interest in Wind Portfolio SponsorCo LLC ("**WP SponsorCo**"), a Delaware LLC; the remaining 1% interest is held by Algonquin Power Fund (America) Holdco Inc., a Delaware corporation which is 100% owned by APFA. WP SponsorCo owns 100% of the Class B managing interests in Wind Portfolio Holdings, LLC ("**WP HoldCo**"), a Delaware LLC. Non-Algonquin partners, JPM Capital Corporation, Morgan Stanley Wind LLC, and Gear Wind LLC, collectively hold 100% of the non-managing Class A interest in WP HoldCo, which in turn owns Wind Energy Portfolio Holdings I, LLC ("**WE HoldCo**"), a Delaware LLC. WE HoldCo directly owns three entities which each own separate wind projects in the USA : Sandy Ridge Wind, LLC, a Delaware LLC, owns the Sandy Ridge wind energy facility (the "Sandy Ridge Wind Facility" in Pennsylvania; Minonk Wind, LLC, a Delaware LLC, owns the Minonk wind energy facility in Illinois (the "Minonk Wind Facility") and Senate Wind, LLC, a Delaware LLC, owns the Senate wind energy facility (the "Senate Wind Facility") in Texas.

APFA owns Shady Oaks Holdings, LLC, a Delaware LLC, which owns TianRun Shady Oaks, LLC, a Delaware LLC, which owns GSG6, LLC, a Delaware LLC, which owns the Shady Oaks Wind Facility in Illinois.

APFA owns Algonquin Power (Odell Holdings) Inc., a Delaware corporation, which owns 50% of Odell SponsorCo, LLC, ("**Odell SponsorCo**") a Delaware LLC. The remaining 50% of Odell SponsorCo is owned by Enel Kansas, LLC, a non-APUC relatedentity. Odell SponsorCo owns Odell Holdings, LLC, a Delaware LLC,which owns Odell Windfarm, LLC, a Minnesota LLC, which owns the Odell Wind Project.

APFA owns Algonquin Power (Deerfield Holdings) Inc., a Delaware corporation which owns a 50% the membership interest in Deerfield Wind SponsorCo, LLC ("Deerfield SponsorCo"), a Delaware LLC acquired from Renewable Energy Systems Americas Inc. ("RES") on October 15, 2015. The remaining 50% of Deerfield SponsorCo is owned by Deerfield Holdings I, LLC, a non-Algonquin subsidiary of RES. Deerfield SponsorCo owns Deerfield Holdco, LLC, a Delaware LLC, which owns Deerfield Wind Energy, LLC, a Delaware LLC which owns the Deerfield Wind Project in Michigan.

APFA owns GB Solar Holdings, LLC, a Delaware LLC, which owns Great Bay Solar I, LLC, a Maryland LLC acquired from Lavaca Wind, LLC, on August 20, 2015. Great Bay Solar I, LLC owns the Great Bay Solar Project in Maryland.

APFA also owns Algonquin Power (Bakersfield Holdings) LLC, ("AP Bakersfield") a Delaware LLC. AP Bakersfield owns 100% of the Class B managing interests in Algonquin SKIC 20 Solar LLC ("SKIC 20") which owns a 20 MW solar facility (the "Bakersfield I Solar Project") in California. The Class A non-managing interests in SKIC 20 are owned by Firstar Development, LLC, a non-APUC relatedentity. AP Bakersfield owns 100% of Algonquin SKIC 10 Solar, LLC ("SKIC 10"), a Delaware LLC, which is developing a 10 MW solar project (the Bakersfield II Solar Project") adjacent to the SKIC 20 project. APFA is also the sole owner ofAlgonquin Power (Bakersfield Land Holdings) LLC, a Delaware LLC which holds the real property associated with the SKIC 10 and SKIC 20 projects.

APFA is also the sole owner of of Algonquin Power Services America LLC, a Delaware LLC that provides purchasing services to APCo entities operating in the U.S.

### (ii) Distribution Business Group

### Distribution Business Group's Electric, Natural Gas, Water, and Wastewater Utilities

Liberty Utilities owns Liberty Utilities (CalPeco Electric), LLC, a California limited liability company ("**CalPeco**"). CalPeco owns an electricity distribution utility in the Lake Tahoe basin and surrounding areas in California ("**CalPeco Electric System**").

Liberty Utilities owns Liberty Utilities (Midstates Natural Gas) Corp. ("**Liberty Midstates**"), a Missouri corporation. Liberty Midstates owns natural gas distribution utility assets in Missouri, Iowa and Illinois (the "**Midstates Gas Systems**").

Liberty Utilities owns Liberty Energy Utilities (New Hampshire) Corp. ("**Liberty Energy (NH)**"), a Delaware corporation registered to do business in New Hampshire. Liberty Energy (NH) owns Liberty Utilities (Granite State Electric) Corp., which owns an electrical distribution utility in New Hampshire (the "**Granite State Electric System**") and Liberty Utilities (EnergyNorth Natural Gas) Corp., which owns a natural gas distribution utility in New Hampshire (the "**EnergyNorth Gas System**").

Liberty Utilities owns Liberty Utilities (Peach State Natural Gas) Corp., a Georgia corporation ("**Peach State**"). Peach State owns natural gas distribution utility assets in Georgia (the "**Peach State Gas System**").

Liberty Utilities owns Liberty Utilities (New England Natural Gas Company) Corp., a Delaware corporation registered to do business in Massachusetts, which owns natural gas distribution utility assets in Massachusetts (the "**New England Gas System**").

Liberty Utilities also owns Liberty Utilities Energy Solutions Corp. ("**Liberty Energy Solutions**"), a Kansas corporation, which in turn owns Liberty Utilities Energy Solutions (Appliance) Corp., a Massachusetts corporation which divested all its assets, namely a retail gas appliance business, in June of 2015. Liberty Energy Solutions also owns Liberty Utilities Energy Solutions (Solar) Corp., a Delaware corporation which owns Liberty Utilities Energy Solutions (Solar 1) Corp., also a Delaware corporation. Liberty Energy Solutions owns Liberty Utilities Energy Solutions (CNG) Corp. and Liberty Utilities Energy Solutions (LNG) Corp., both being Delaware corporations.

Liberty Utilities owns Western Water Holdings, LLC, a Delaware LLC, which owns Liberty Utilities (Park Water) Corp. ("**Park Water**"), which owns the Park Water System in Downey, California. Park Water also owns Mountain Water Company ("Mountain Water"), a Montana company which owns the Mountain Water Facility in Missoula, Montana, and Liberty Utilities (Apple Valley Ranchos Water) Corp. ("Apple Valley"), a California company which owns the Apple Valley Ranchos water facility ( the "Apple Valley Ranchos Water System") in Apple Valley, California. These assets were acquired on January 11, 2016.

On February 9, 2016, APUC announced that it has entered into an agreement with the Empire District Electric Company. ("**Empire**"), a Kansas corporation, to purchase all of the issued and outstanding common shares of Empire. The transaction, which has the approval of the boards of both companies but is subject to shareholder, state and U.S. federal approvals, is expected to close in the first quarter of 2017. In contemplation of the proposed transaction, Liberty Utilities has formed Liberty Utilities (Central) Co., a Delaware corporation, which in turn has formed Liberty SubCo, a Kansas Corporation. Assuming the transaction closes as anticipated, Liberty SubCo will merge with Empire with Empire being the surviving entity. Empire owns the Empire District Gas Company, and Empire District Industries Inc., both Kansas corporations. Please see ["*Recent Development - 2016 - Corporate*"] for a detailed description and discussion of the proposed transaction with Empire.

Liberty Utilities also owns Liberty Utilities (Pine Bluff Water) Inc., which owns and operates the Pine Bluff Water System, located in Pine Bluff, Arkansas.

Liberty Utilities owns Liberty Utilities (White Hall Water) Corp. and Liberty Utilities (White Hall Sewer) Corp., both being Arkansas corporations, which respectively own the White Hall Water System and the White Hall Waste System in Arkansas.

### Liberty Utilities (Sub) Corp.

Liberty Utilities owns Liberty Utilities**SubCo**, which is a Delaware company. With the exception of the Pine Bluff Water, Mountain Water, Apple Valley Ranchos Water System, the Park Water System and the White Hall Water and Waste System, Liberty SubCo is the parent company of the water and wastewater entities.

Liberty SubCo owns, through subsidiaries, the water and wastewater businesses located in Arizona, Texas, Missouri and Illinois. Most of these 100% wholly-owned subsidiaries (except Liberty Utilities (Northwest Sewer) Corp. ), are currently conducting business as "Liberty Utilities"; however the actual legal names of the relevant entities are set out below.

In Arizona, the following Arizona corporations own the following facilities: Liberty Utilities (Bella Vista Water) Corp. owns the Bella Vista Water System, the Northern Sunrise Water System, and the Southern Sunrise Water System; Liberty Utilities (Black

Mountain Sewer) Corp. owns the Black Mountain Waste System; Liberty Utilities (Gold Canyon Sewer) Corp. owns the Gold Canyon Waste System; Liberty Utilities (Litchfield Park Water & Sewer) Corp. owns the Litchfield Waste & Water Systems; Liberty Utilities (Rio Rico Water & Sewer) Corp. owns the Rio Rico Water & Waste Systems; and Liberty Utilities (Entrada Del Oro Sewer) Corp. owns the Entrada Del Oro Waste System.

In Texas, the following Texas corporations own the following facilities: Liberty Utilities (Tall Timbers Sewer) Corp. owns the Tall Timbers Waste System; Liberty Utilities (Woodmark Sewer) Corp. owns the Woodmark Waste System; Liberty Utilities (Silverleaf Water), LLC, a Texas limited liability company, owns water and wastewater treatment assets at the Holly Lake Ranch, Hill County, Piney Shores and The Villages (also known as "Big Eddy") Resorts; and Liberty Utilities (Seaside Water), LLC., a Texas limited liability company, owns water and wastewater treatment assets at the Seaside Resort.

In Missouri, Liberty Utilities (Missouri Water), LLC, a Missouri limited liability company, owns assets associated with the Holiday Hills, Ozark Mountain, Timbercreek resorts, the water utility in Noel, Missouri and a utility in eastern Missouri. In Illinois, Liberty Utilities (Fox River Water), LLC, an Illinois limited liability company, owns assets serving the Fox River Resort.

#### (iii) Transmission Business Group

On the U.S. side of the Transmission Group, Liberty Utilities (Pipeline & Transmission) Corp. owns 2.5% of Northeast Expansion and 4.0% of Northeast Supply Pipeline LLC ("Northeast Supply"), both of which are Delaware LLCs. Kinder Morgan Operating Limited Partnership "A", a non-Algonquin partner, owns the remaining 97.5% of Northeast Expansion and the remaining 96% of Northeast Supply. Pipeline & Transmission also owns 50% of Northeast Energy Center, LLC, a Delaware corporation. The remaining 50% is owned by RBS Energy, LLC, a non-APUC related entity.

In Canada, LU Canada owns Algonquin Power (Ontario Transmission) Inc., an Ontario corporation, which owns 50% of Sagatay Holdings Partnership, an Ontario general partnership. The remaining 50% is owned by Morgan Geare Inc., a non-APUC related entity. Sagatay Holdings Partnership owns 49.99% of Sagatay Transmission Limited Partnership, ("Sagatay LP") an Ontario limited partnership. Sagatay LP is also owned 25% by the Mishkeegogamang First Nation and 25% by the Ojibway Nation of Saugeen First Nation, both of which are non-Algonquin entities. LU Canada also owns Liberty Utilities (Sagatay Transmission) GP Inc., an Ontario corporation, which owns the remaining 0.01% of Sagatay LP and acts as its general partner.

#### (iv) Other

Outside of APCo, LU Canada and their respective subsidiary entities, as described above, APUC directly owns Warwick (Canada) Corp., an Ontario corporation and 3793257 Canada Inc. ("**3793257**"), a holding company incorporated under the Canada Business Corporation Act.

APUC also has ownership interests in a group of special purpose financing entities, including 90% of Liberty Utilities Finance GP 1 ("**LU GP1**"), a Delaware general partnership. LU GP1 owns 99.9% of Liberty Utilities Finance GP 2 ("**LU GP2**"), a Delaware general partnership. The minority partner of both LU GP1 and LU GP2 is 3793257. LU GP2 owns Liberty Utilities Finance (Canada) ULC, an Alberta unlimited liability corporation which in turn owns Liberty Utilities Finance (US) LLC, a Delaware limited liability company. The above entities were formed as special purpose financing entities used in Liberty Utilities financings.

LU Canada controls a limited partnership formed for purposes of holding the corporate head office location. LU Canada owns 99.99% of Davis Road LP, an Ontario limited partnership, and it also owns 100% of Davis Road GP Inc., the general partner and 0.01% owner of Davis Road LP.

### 1.2.2 Other Interests in Energy Related Developments

The Corporation also has notes receivable and equity in companies owning generating facilities as described below. APT owns 25% of the Class B non-voting shares issued by Cochrane Power Corporation, the owner of a combined cycle cogeneration facility located in Cochrane, Ontario. APT also owns 32.4% of the Class B non-voting shares in Kirkland Lake Power Corporation, an entity which burns natural gas and wood waste to generate electricity. It also owns a 33.9% interest in the Class B non-voting preferred shares of Chapais Energie, Société en Commandite.

In addition, APCo is entitled to a royalty in the form of cash flows generated by the Long Sault Hydro Facility . It is also the owner of a 14.14% secured, subordinated note in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc.

APUC also owns the Class B limited partnership units of St. Leon LP, the legal owner of the St. Leon Wind Facility.

# 2. GENERAL DEVELOPMENT OF THE BUSINESS

## 2.1 General

### 2.1.1 Business Strategy

APUC owns and operates a diversified portfolio of regulated and non-regulated generation, distribution and transmission utility assets which deliver predictable earnings and cash flows. APUC seeks to maximize total shareholder value through a quarterly dividend augmented by share price appreciation arising from dividend growth supported by increasing per share cash flows and earnings.

APUC's current quarterly dividend to shareholders is U.S. $0.09625 per share or U.S. $0.3850 per share on an annual basis. Based on exchange rates as at March 10, 2016, the quarterly dividend is equivalent to CAD $0.12872 per share or CAD $0.51486 per share per annum. APUC believes its annual dividend payout allows for both an immediate return on investment for shareholders and retention of sufficient cash within APUC to fund growth opportunities and mitigate the impact of fluctuations in foreign exchange rates. Further increases in the level of dividends paid by APUC are at the discretion of the APUC's Board of Directors (the "Board") with dividend levels being reviewed periodically by the Board in the context of cash available for distribution and earnings together with an assessment of the growth prospects available to APUC. APUC strives to achieve its results in the context of a moderate risk profile consistent with top-quartile North American power and utility operations.

APUC's operations are organized across three business unit groups consisting of the Generation, Transmission and Distribution Groups. The Generation Group owns and operates a diversified portfolio of non-regulated renewable and thermal electric generation utility assets, the Transmission Group is responsible for evaluating and capitalizing upon natural gas pipeline and electric transmission asset opportunities in North America, and the Distribution Group owns and operates a portfolio of North American electric, natural gas and water distribution and wastewater collection utility systems.

**Generation Business Group**: The Generation Group generates and sells electrical energy produced by its diverse portfolio of non-regulated renewable and clean energy power generation facilities located across North America. The group delivers continuing growth through development of new greenfield power generation projects and accretive acquisitions of additional electrical energy generation facilities.

The Generation Group owns or has interests in hydroelectric, wind, solar, and thermal facilities with a combined generating capacity of approximately 120 MW, 700 MW, 30MW, and 335 MW respectively. Approximately 83% of the electrical output from the hydroelectric, wind and solar generating facilities is sold pursuant to long term contractual arrangements which have a weighted average remaining contract life of 14 years.

The Generation Group also has a portfolio of development projects that between 2016 and 2018 will add approximately 711 MW of generation capacity from wind and solar powered generating facilities with an average contract life of 21 years.

Detailed information on the facilities owned and operated by APCo is set out in Schedules A and B.

**Distribution Business Group:** The Distribution Group operates diversified rate regulated electricity, natural gas, water distribution and wastewater collection utility services to approximately 489,000 connections, excluding the Park Water System. The Distribution Group provides safe, high quality and reliable services to its ratepayers through its nationwide portfolio of utility systems and delivers stable and predictable earnings to APUC. In addition to encouraging and supporting organic growth within its service territories, the Distribution Group delivers continued growth in earnings through accretive acquisition of additional utility systems.

The Distribution Group's regulated electrical distribution utility systems and related generation assets are located in the States of California and New Hampshire; and together serve approximately 93,000 electric connections.

The Distribution Group's regulated natural gas distribution utility systems are located in the States of Georgia, Illinois, Iowa, Massachusetts, Missouri and New Hampshire; and together serve approximately 292,000 natural gas connections.

The Distribution Group's regulated water distribution and wastewater collection utility systems are located in the States of Arizona, Arkansas, Illinois, Missouri, and Texas; and together serve approximately 104,000 connections. On January 8, 2016, the Distribution Group completed its acquisition of the Park Water System which is comprised of two water and wastewater facilities in California and one facility in Montana. This acquisition adds approximately 74,000 connections to the Distribution Group's present water and wastewater footprint.

**Transmission Business Group**: In 2014, APUC created a Transmission Group that is responsible for identifying, evaluating and capitalizing upon natural gas pipeline and electric transmission investment opportunities in North America. The Corporation believes that the creation of the Transmission Group complements the growth of both the Generation and Distribution Groups.

## 2.2 Three Year History and Significant Acquisitions

The following is a description of the general development of the business of the Corporation over the last three fiscal years.

### 2.2.1 Fiscal 2013

#### Corporate

#### (i) Dividend Increased to $0.34 per Common Share Annually

Resulting from a higher growth profile and consistent with APUC's stated strategy of delivering total shareholder return comprised of an attractive current dividend yield and capital appreciation, on May 9, 2013, the Board approved a dividend increase of $0.03 per share annually bringing the total annual dividend to $0.34, paid quarterly at the rate of $0.085 per Common Share.

#### (ii) Credit Rating Upgrade

In the fourth quarter of 2013, S&P raised its long-term corporate credit rating on APUC, APCo and Liberty Utilities to 'BBB' from 'BBB-'. As well, S&P raised its global scale and Canada scale preferred stock ratings on APUC to 'BB+' and 'P-3 (High)' from 'BB' and 'P-3', respectively. S&P provided a stable outlook for APUC owing to the assessment of relatively stable cash flows, supported by regulated cash flow from Liberty Utilities' regulated utility business, and APCo's largely contracted power asset portfolio.

#### (iii) Related Party Transactions

In 2011, the Board formed an independent committee ("**Independent Board Committee**") and initiated a process to review all of the remaining historic business associations with APUC's Chief Executive Officer ("**CEO**") and Vice-Chair with an objective to reduce and/or eliminate these relationships. The process was largely completed during the 2013 fiscal year and the processes to resolve related party transactions between APUC and the CEO and Vice Chair have been identified to the satisfaction of the Independent Board Committee and the Board. See "*Description of Business - Business Associations with APMI and Senior Executives*".

#### (iv) Emera Subscription Receipts

Pursuant to previously committed Subscription Receipts of APUC (the "Subscription Receipts"), on February 7, 2013, APUC issued 2,614,005 Common Shares at a price of $5.74 per share to Emera Inc. ("Emera"). Additionally, on February 14, 2013, APUC issued 5,228,011 Common Shares at a price of $5.74 per share and 3.4 million Common Shares at a price of $4.72 per share to Emera. On March 26, 2013, APUC issued 4.0 million Common Shares at a price of $7.40 per share for total cash proceeds of $29.3 million pursuant to a subscription agreement with Emera.

APUC believes the issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

#### (v) Conversion and Redemption of Series 3 Convertible Debentures to Equity

On January 2, 2013, APUC completed a redemption of the 7% convertible unsecured debentures due June 30, 2017 (the"Series 3 Debentures") by issuing and delivering 150,816 Common Shares for the remaining $1.0 million principal amount of Series 3 Debentures outstanding.

#### (vi) Expansion of the Corporate Credit Facility

On November 19, 2013, APUC amended its senior unsecured revolving credit facility ("the Corporate Credit Facility") to increase the commitments available to $65.0 million and extend the maturity date to November 19, 2016.

#### Generation Group

#### (i) Acquisition of the 20 MW Bakersfield Solar Project

On November 28, 2013, the Generation Group entered into an agreement to purchase and complete construction of a 20 MW solar facility (the "**Bakersfield Solar I Project**") located in Kern County, California. Following commissioning, the Bakersfield Solar I Project is expected to generate 53.3 GWh of energy per year. All energy from the project will be sold to Pacific Gas & Electric Company ("PG&E") pursuant to a 20 year agreement. The Generation Group entered into a partnership agreement with a third party (the "**Tax Partner**") pursuant to which the Tax Partner will receive the majority of the tax attributes associated with the project. The Tax Partner contributed U.S. $22.4 million to the project with the remainder of the total cost of U.S. $58.4 million funded by the Generation Group.

Please see ["Fiscal 2015 - Generation Group"] for additional information on the Bakersfield Solar Project.

### (ii) Acquisition of Shady Oaks Wind Facility

On January 1, 2013, APCo acquired a 109.5 MW contracted wind generating facility (the "**Shady Oaks Wind Facility**") from Goldwind International SO Limited ("**Goldwind**") by assuming long-term debt of U.S. $150 million for no additional cash, subject to final closing adjustments for working capital, energy generated by the project and basis differences between node and hub prices.

The Shady Oaks Wind Facility is located in Northern Illinois, approximately 80 km west of Chicago, Illinois and achieved commercial operation in June 2012.

The facility is comprised of 68 Goldwind GW82 1.5MW and 3 Goldwind GW100 2.5MW permanent magnet direct-drive wind turbines; these turbines are well suited for the wind regime, and offer significant technological advantages providing proven reliability, enhanced energy production efficiency and lower long term maintenance costs. An affiliate of Goldwind has assumed all operations, maintenance, and capital repair responsibilities for the Shady Oaks Wind Facility turbines pursuant to a 20 year fixed price agreement.

The Shady Oaks Wind Facility has entered into a 20 year inflation indexed power purchase agreement with the largest electric utility in the state of Illinois, Commonwealth Edison (BBB flat stable: Moody's, S&P) for 310 GWh of energy per year. All energy produced in excess of that sold under the power purchase agreement is sold into the energy market in which the facility is located.

### (iii) Energy From Waste Facility

During the second quarter of 2013, the Generation Group concluded that the Energy from Waste Thermal Facility ("EFW Thermal Facility") and Brampton Cogeneration Inc.'s thermal facility (the "BCI Thermal Facility") were no longer considered strategic to its ongoing operations, commenced a process to divest of the facilities and wrote the net assets of the facilities down to their estimated fair value, less cost of sale which resulted in a write down of $35.7 million, net of tax. On February 7, 2014, an agreement to sell the EFW and BCI Thermal Facilities was reached. Accordingly, the determination of the fair values of the net assets of EFW and BCI Thermal Facilities were revised to reflect the estimated selling price under the agreement, which resulted in a further write down of the net assets of $6.8 million net of tax as at December 31, 2013. The transaction closed on April 4, 2014.

### (iv) Sale of Small U.S. Hydro Facilities

On March 14, 2013, the Generation Group entered into an agreement to sell ten small U.S. hydroelectric generating facilities that were no longer considered strategic to the ongoing operations of APUC for gross proceeds of U.S. $27.0 million. The Generation Group closed the sale of nine of the ten facilities on June 29, 2013 for total proceeds of approximately U.S. $23.4 million with the sale of the tenth facility closing on June 17, 2014.

## Distribution Group

### (i) Acquisition of the New England Gas System

On February 11, 2013, the Distribution Group entered into an agreement with The Laclede Group, Inc. ("**Laclede**") to assume Laclede's rights to purchase the assets of the New England Gas Company from an affiliate of Southern Union Company. The New England Gas System is a natural gas distribution utility serving over 55,000 connections in Massachusetts. The acquisition closed in the fourth quarter of 2013.

Total purchase price for the New England Gas System, net of the debt assumed was approximately U.S. $62.7 million, including the purchase price adjustment of U.S. $3.1 finalized in the second quarter of 2014. The acquisition was funded using a targeted 52% equity, 48% debt capital structure including the assumption of U.S. $19.5 million of existing debt.

### (ii) Acquisition of the Peach State Gas System

On August 8, 2012, the Distribution Group entered into an agreement with ATMOS Energy Corporation to acquire certain regulated natural gas distribution utility systems in Georgia serving approximately 60,000 connections in the State of Georgia. On April 1, 2013 the Distribution Group completed the acquisition for a total purchase price adjusted for certain working capital and other closing adjustments of approximately U.S. $153.0 million.

### (iii) Acquisition of the Pine Bluff Water System

On February 1, 2013, the Distribution Group completed the acquisition of the issued and outstanding shares of United Water Arkansas Inc., a regulated water distribution utility (the "Pine Bluff Water System") from United Waterworks Inc. The Pine Bluff Water System is located in Pine Bluff, Arkansas and serves approximately 17,700 water distribution connections. Total purchase price for the Pine Bluff Water System, adjusted for certain working capital and other closing adjustments, was approximately U.S. $27.9 million.

### (iv) U.S. Debt Private Placements

On July 31, 2013, the Distribution Group issued U.S. $125.0 million of debt through a private placement in the U.S. The financing is the third series of notes issued pursuant to Liberty Utilities' master indenture. The notes are senior unsecured with an average life maturity of approximately ten years and a weighted average coupon of 3.81%. The proceeds of the private placement financing were used to repay a U.S. $100.0 million short term acquisition facility used in connection with the acquisition of the Peach State Gas System, reduce the drawn amount on the Generation Group's senior unsecured credit facility (the "Generation Credit Facility") and for general corporate purposes.

On March 14, 2013, the Distribution Group completed a U.S. $15.0 million private placement debt financing. The notes are senior unsecured with a 10 year term and a coupon of 4.14%.

### (v) Expansion of the Distribution Credit Facility

On September 30, 2013, the Distribution Group increased the credit available under its revolving credit facility (the "**Distribution Credit Facility**") the Distribution Credit Facility to U.S. $200.0 million from U.S. $100.0 million. The larger credit facility provides the Distribution Group with the additional liquidity required as a result of the various acquisitions completed in 2013 and for execution of near term organic growth opportunities. In addition to a larger credit facility, the tenor has been increased from three years to five years and several other terms under the facility, including pricing, were improved. The amended facility now expires on September 30, 2018.

### (vi) Successful Completion of the Rio Rico System Rate Case

On May 31, 2012, the Distribution Group filed a general rate case with the Arizona Corporation Commission ("ACC") related to the Rio Rico System. The filing sought, among other things, an increase in EBITDA by U.S. $0.8 million over 2011 results if approved as filed. On July 17, 2013, an order was received from the ACC which corresponds to an increase in EBITDA of approximately U.S. $0.4 million per year.

### (vii) Successful Completion of the EnergyNorth Gas System Rate Case

On May 15, 2013, the Distribution Group filed its required fiscal year 2013 (April 1, 2012 - March 31, 2013) cast iron/bare steel (CIBS) replacement program results for EnergyNorth Gas System with the New Hampshire Public Utilities Commission ("NHPUC"). As part of this filing, Liberty requested an annual increase in base distribution rates of U.S. $0.2 million effective July 1, 2013. On June 26, 2013, the NHPUC approved the increase.

### (viii) Successful Completion of the Midstates Gas System Rate Case

On July 2, 2013, the Distribution Group filed an application with the Missouri Public Service Commission ("**MPSC**") seeking accelerated recovery for infrastructure deployed under the Midstates Gas System's infrastructure system replacement surcharge ("**ISRS**"). The filing was approved by MPSC on October 16th, 2013 which is expected to increase revenues and EBITDA by U.S. $0.6 million.

## 2.2.2 Fiscal 2014

### Corporate

### (i) Dividend Increased to U.S. $0.35 Per Common Share Annually

In 2014 the Corporation successfully advanced various initiatives raising the growth profile for earnings and cash flows which in turn supported an increase in the dividend to shareholders. As a result, on August 14, 2014, the Board approved a dividend increase to U.S. $0.35 per share per annum, paid quarterly at a rate of U.S. $0.0875 per share, a 12.4% increase over the previous dividend of CDN $0.34 calculated using the exchange rate in effect at that time. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. In 2014, APUC's consolidated assets were approximately 80% based in the U.S. and generated approximately 77% of its underlying cash flows.

### (ii) Issuance of $100 million Preferred Shares

On March 5, 2014, APUC issued 4.0 million cumulative rate reset preferred shares, Series D (the "**Series D Shares**") at a price of $25 per share, for aggregate gross proceeds of $100.0 million. The Series D Shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS, respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

### (iii) Issuance of Common Shares

On September 16, 2014, APUC completed a public offering (the "**September Offering**") of 16,860,000 Common Shares at a price of $8.90 per share, for gross proceeds of approximately $150.0 million. On September 26, 2014, the underwriters exercised the over-allotment option granted with the September Offering and an additional 2,529,000 Common Shares were issued on the same terms and conditions of the September Offering. As a result, APUC issued an aggregate of 19,389,000 Common Shares under the Offering for the total gross proceeds of approximately $172.6 million.

On December 11, 2014, APUC completed a public offering of 10,055,000 Common Shares at a price of $9.95 per share, for gross proceeds of approximately $100.0 million.

Net proceeds of both Common Share offerings were used to finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities, and for general corporate purposes.

### (iv) Private Placement of Subscription Receipts to Emera Inc.

On September 4, 2014, APUC and Emera entered into a subscription agreement pursuant to which Emera agreed to subscribe for an aggregate of 7,865,170 Subscription Receipts of APUC at a price of $8.90 per Subscription Receipt, for an aggregate subscription amount of $70.0 million.

On September 26, 2014, as a result of the underwriters exercising their over-allotment option, an additional 843,000 Subscription Receipts were issued to Emera at a price of $8.90 per Subscription Receipt, for an aggregate subscription amount of $77.5 million.

On December 2, 2014, APUC and Emera entered into an additional subscription agreement to which Emera agreed to subscribe for an aggregate of 3,316,583 Subscription Receipts at a price of $9.95 per Subscription Receipt, for an aggregate subscription amount of $33.0 million.

The proceeds of the Subscription Receipts private placements are intended to be used to partially finance the acquisitions of the Odell Wind Project and Park Water System.

## Generation Group

### (i) Acquisition of Odell Wind Project

On September 4, 2014, the Generation Group announced an opportunity to acquire an interest in a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota (the "Odell Wind Project"). The Odell Wind Project is being constructed on approximately 23,000 acres of leased land and will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year power purchase agreement ("PPA"), all energy, capacity and Renewable Energy Credits ("REC") from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S. Construction of the project began in the second quarter of 2015, with total costs to complete estimated at U.S. $322.8 million. It is anticipated that the Odell Wind Project will qualify for U.S. federal production tax credits, accordingly the project company has entered into a partnership agreement with third parties (tax equity) to contribute approximately $180 million USD to the project in return for the majority of the tax attributes. Construction financing including a portion that bridges to tax equity's investments was arranged by the project company during 2015.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Corporation is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of commercial operations, which is expected in the second quarter of 2016.

Please see ["*Business Development - Current Development Projects*"] for further information regarding the Odell Wind Project.

### (ii) Completion of Cornwall Solar Project

During the quarter ended March 31, 2014, the Generation Group completed the construction of its 10 MW solar project located near Cornwall, Ontario. The facility reached commercial operation on March 27, 2014. The facility represents the first solar project in the Generation Group's portfolio. The facility is expected to generate approximately 14,400 MW-hrs of electricity annually with the power sold under a 20 year feed in tariff ("FIT") contract with the Independent Electricity System Operator ("**IESO**"), formerly the Ontario Power Authority ("**OPA**").

### (iii) Completion of St. Damase Wind Project

On December 2, 2014, the first phase of the wind facility located in the local municipality of Saint-Damase (the "**Saint-Damase Wind Project**") reached commercial operations. The 24 MW facility is expected to generate 76,900 MW-hrs of electricity annually with the power sold under a 20 year PPA with Hydro Quebec Distribution ("Hydro Quebec).

It is expected that the turbines and other components utilized in the first 24 MW phase of the Saint-Damase Wind Project will qualify as Canadian Renewable and Conservation Expense ("**CRCE**"), and therefore a significant portion of the Phase I capital cost will be eligible for a refundable Quebec tax credit ("**Quebec CRCE Tax Credit**"). The estimated value of the Quebec CRCE tax credit for the Saint-Damase Wind Project is expected to be approximately $15.0 million. Phase II of the project will be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting, and entering into appropriate energy sales arrangements.

### (iv) Expansion of Bakersfield I Solar Project

On November 24, 2014, APUC announced that it intends to proceed with a 10 MW project (the "**Bakersfield II Solar Project**") adjacent to its 20MW Bakersfield I Solar Project in Kern County, California.

The 10MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20MW Bakersfield I Solar Project which achieved COD on April 14, 2015.

The total project cost for the Bakersfield II Solar Project of approximately U.S. $27.0 million will be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including the Bakersfield I Solar Project, it is anticipated that the Bakersfield II Solar Project will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

### (v) Acquisition of the Remaining 40% of a 400 MW Wind Power Portfolio

On March 31, 2014, the Generation Group acquired from Gamesa Wind US, LLC ("**Gamesa**") the remaining 40% of the Class B partnership units of the entity which owns a three facility 400 MW wind portfolio in the United States (the "U.S. Wind Portfolio") for total consideration of approximately U.S. $115.0 million. As a result of the transaction, the Generation Group now owns 100% of the Class B partnership units of the entity that owns the U.S. Wind Portfolio. Gamesa will continue to provide operations, warranty and maintenance services for the wind turbines and balance of plant facilities under 20 year contracts. The acquisition was funded primarily from the proceeds from the $200.0 million of debentures issued by the Generation Group early in 2014 as discussed below.

### (vi) $200 million Senior Unsecured Debentures

On January 17, 2014, the Generation Group issued $200.0 million 4.65% senior unsecured debentures with a maturity date of February 15, 2022 (the "2014 Generation Group Debentures") pursuant to a private placement in Canada and the United States. The 2014 Generation Group Debentures were sold at a price of $99.864 per $100.00 principal amount resulting in an effective yield of 4.67%. Concurrent with the offering, the Generation Group entered into a fixed for fixed cross currency swap, coterminous with the debentures, to economically convert the Canadian dollar denominated debentures into U.S. dollars, resulting in an effective interest rate throughout the term of approximately 4.77%.

Net proceeds were used towards financing the acquisition of the remaining 40% ownership interest in its U.S. Wind Portfolio, to reduce amounts outstanding on project debt related to its Shady Oaks Wind Facility, to reduce amounts outstanding under its bank credit facility, and for general corporate purposes.

### (vii) Additional Liquidity

On July 31, 2014, the Generation Group increased the credit available under the Generation Group Credit Facility to $350.0 million from $200.0 million. The larger credit facility provides additional liquidity in support of the group's $1,835.2 million development portfolio to be completed over the next three years. In addition to the larger size, the maturity of the facility has been extended from three to four years and now extends until July 31, 2018

## Distribution Group

### (i) Agreement to acquire Park Water

On September 19, 2014, the Distribution Group announced the entering into an agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("**Park Water**"). The Park Water acquisition closed on January 8, 2016.

Please see ["Recent Developments - 2016 - Distribution"] for a detailed description of the Park Water acquisition.

### (ii) Acquisition of White Hall Water System

On May 30, 2014, the Distribution Group acquired the assets of the White Hall water and waste system (the "**White Hall Water System**" and "**White Hall Waste System**" respectively" and together the "White Hall Water and Waste System") , a regulated water distribution and wastewater treatment utility located in White Hall, Arkansas. The White Hall Water and Waste System serves approximately 1,900 water distribution and 2,400 wastewater treatment customers. Total purchase price for the White Hall Water System assets, adjusted for certain working capital and other closing adjustments, is approximately U.S. $4.5 million.

### (iii) Successful Completion of the Granite State Electric System Rate Case

In the first quarter of 2013, the Granite State Electric System filed a rate case with the NHPUC seeking an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014.

### (iv) Successful Completion of the Peach State Gas System GRAM Filings

On October 1, 2013, the Peach State Gas System filed an application for an increase in revenue of U.S. $4.9 million in its annual Georgia Rate Adjustment Mechanism ("GRAM") filing with the Georgia Public Service Commission ("GPSC"). In January 2014, the Distribution Group and the staff of the GPSC agreed to a settlement which will provide an annual revenue increase of U.S. $3.2 million, and the recovery of U.S. $1.7 million of carrying charges on deferred rate base in a future GRAM filing. Commission approval was received in May 2014, with new rates effective as of June 1, 2014.

On October 1, 2014, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.7 million in its annual GRAM filing with the GPSC. New rates to be effective February 1, 2015 for the period February 1, 2015, through January 31, 2016 were to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 30, 2014 (Historic Test Year) with adjustments for the 12 months ending August 31, 2015 (Forward Looking Test Year). GPSC approval was received on December 4, 2014.

### (v) Successful Completion of the LPSCo Water System Rate Case

On February 28, 2013, the LPSCo Water distribution and wastewater treatment facility (the "**LPSCO System**")filed a general rate case with the ACC related to the LPSCo System sought, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years, and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. In April 2014 the commission approved a $1.8 million increase in rates effective on May 1, 2014.

### (vi) Successful Completion of the Midstates Gas System Rate Case

On February 6, 2014, the Midstates Gas System filed a rate case with the **MPSC** seeking an increase in revenue of U.S. $7.6 million, consisting of U.S. $6.3 million in new, incremental revenue and U.S. $1.3 million through the ISRS . The filing is based on a test year ending September 30, 2013, with revenues, expenses and rate bases adjusted to reflect known and measurable changes through April 30, 2014. The case has concluded and an Order was issued on December 3, 2014, approving a U.S. $4.9 million revenue increase effective January 2, 2015.

### (vii) Pine Bluff Water System Rate Case Proceedings

On July 2, 2014, Pine Bluff Water System filed an application with the Arkansas Public Service Commission ("**APSC**") seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. On March 12, 2015, the Pine Bluff Water System received a Final Order from the Arkansas Public Service Commission approving a revenue increase of U.S. $1.1 million effective March 15, 2015.

### (viii) EnergyNorth Gas System Rate Case Proceedings

On August 1, 2014, the EnergyNorth Gas System in New Hampshire filed an application for an increase in revenue of U.S. $16.1 million, or approximately 9.6%. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Distribution Group ownership. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates. On June 26, 2015, the EnergyNorth Gas System received a Final Order from the New Hampshire Public Utility Commission approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

### Transmission Group

#### (i) Agreement to acquire interest in Natural Gas Transmission Pipeline

On November 24, 2014, APUC announced its agreement to participate in a Northeast natural gas pipeline transmission project in partnership with Morgan, Inc ("Kinder Morgan") in connection with Kinder Morgan's Northeast Energy Direct project to service New England natural gas markets. Specially, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, agreed to form **Northeast Expansion LLC** to undertake the development, construction and ownership of a 30-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "Market Path Project"). The project is scalable up to 1.3 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local distribution utilities, and other customers, to help ease constraints on natural gas supply in the northeast U.S. and help ensure much needed reliability to the power-generation grid. It is anticipated that the project will receive a Federal Energy Regulation Commission ("**FERC**") certificate in the fourth quarter of 2016, with commercial operations occurring by late 2018.

Under the agreement, APUCinitially subscribed for a 2.5% interest in Northeast Expansion. . The Transmission Group expects to invest approximately $5.0 million (US$3.8 million) in the Market Path Project in 2016. As proposed, the potential investment could exceed US$300 million over a three-year period if APUC elects to increase its interest.

### 2.2.3 Fiscal 2015

### Corporate

#### (i) Dividend Increased in second quarter 2015 to U.S. $0.385 Per Common Share Annually

On May 7, 2015, the Board approved a dividend increase of U.S. $0.035 annually bringing the total annual dividend to U.S. $0.385 per common share, paid quarterly at the rate of U.S. $0.0963 per common share, an increase of 10% over the previous dividend rate. This most recent dividend increase represents the fifth year in a row that APUC has increased the dividend to common shareholders.

The 2015 equivalent Canadian dollar dividends per common share have been as follows:

| | Q1 2015 | Q2 2015 | Q3 2015 | Q4 2015 | Annual |
|---|---|---|---|---|---|
| U.S. dollar Dividend | $0.0875 | $0.0963 | $0.0963 | $ 0.0963 | $0.3764 |
| Canadian dollar equivalent | $0.1108 | $0.1202 | $0.1289 | $ 0.1267 | $0.4866 |

#### (ii) $150 Million Bought Deal Offering Common Shares

On December 2, 2015 APUC issued on a bought deal basis (the "December Offering") 14,355,000 Common Shares at a price of $10.45 per share for gross proceeds of approximately $150 million.

Net proceeds of the December Offering are being used to partially fund APUC's capital growth program, to reduce short-term debt and for general corporate purposes.

### Generation Group

#### (i) Deerfield Wind Project Joint Venture

On October 19, 2015, the Generation Group announced it has agreed to jointly develop a 150 MW construction stage wind project (the "Deerfield Wind Project") in the United States with RES.

The Deerfield Wind Project is located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group. The project will utilize 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GWh annually. The project has a 20 year power purchase agreement ("PPA") with a local electric distribution utility serving approximately 260,000 customers in Michigan.

The total project cost is expected to be approximately U.S. $303.0 million. The project is expected to achieve commercial operation at the end of 2016, with its first full year of operation being 2017.

#### (ii) Great Bay Solar Project

On December 1, 2015, the Generation Group announced the development of a new 75 MW contracted solar generation facility, located in Somerset County Maryland ("Great Bay Solar Project"). The U.S. $180.0 million facility will be constructed over the next twelve months, with commercial operations expected in late 2016 or early 2017. The facility is contracted under a

10 year PPA and expected to generate 152 GWh annually. The facility will also generate Solar Renewable Energy Credits (SRECs) which will be sold into the Maryland market.

#### (iii) Letter of Credit Facility

On October 30, 2015, the Generation Group entered into a new extendible one year letter of credit facility agreement (the "New Facility"). The New Facility expands the group's available liquidity by providing for issuances of letters of credit based on two separate tranches of Cdn $50.0 million and U.S. $30.0 million. Upon closing, certain letters of credit issued on the existing Generation Credit Facility were transferred to the New Facility.

#### (iv) Completion of Morse Wind Facility

On April 22, 2015 the Generation Group completed construction a 23 MW wind generating facility, located near Morse, Saskatchewan ( the "Morse Wind Facility"). The facility is the Generation Group's eighth wind generating facility and consists of 10 2.3 MW direct drive wind turbine generators installed over 1,120 acres of land. The facility is expected to generate 104 GWh of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

#### (v) Completion of Bakersfield I Solar Project

On April 14, 2015 the Generation Group achieved commercial operation in accordance with the provisions within the PPA on the 20 MW solar generating facility located in Kern County, California (the "Bakersfield I Solar Project"). The facility is the Generation Group's second solar generating facility and is comprised of approximately 85,000 solar panels located on 165 acres of land. The project is expected to generate 53.3 GWh of energy per year which is being sold under a 20 year PPA with a large investment grade electric utility.

Consistent with the commitment to expand its solar generation portfolio, the Generation Group is currently pursuing the construction of the 10 MW Bakersfield II Solar Project immediately adjacent to the Bakersfield I SolarProject, which is estimated to be operational in the first half of 2016.

### Distribution Group

#### (i) Successful Rate Case Outcomes

A core strategy of the Distribution Group is to ensure an appropriate return on the rate base at its various utility systems. During 2015, the Distribution Group successfully completed several rate cases representing a cumulative annual revenue increase of approximately U.S. $18.1 million. The full annualized impact of these rate cases will be realized in 2016.

#### (ii) U.S. Debt Private Placement

On April 30, 2015, the Distribution Group entered into a Note Purchase Agreement for the issuance of U.S. $160.0 million of senior unsecured 30 year notes bearing a coupon of 4.13% via a private placement in the U.S. The proceeds of the financing was used to partially finance the acquisition of the Park Water System and for general corporate purposes. The notes were issued in two tranches: U.S. $90.0 million was issued immediately on closing and U.S. $70.0 million were issued on July 15, 2015. The notes have been assigned a rating of BBB High by DBRS.

The financing is the fourth series of notes issued pursuant to the Corporation's master indenture.

#### (ii) Acquisition of New Hampshire Gas

On January 2, 2015, the Distribution Group completed the acquisition of the New Hampshire Gas Corporation (the "New Hampshire Gas System"), a regulated propane gas distribution utility located in Keene, New Hampshire. The New Hampshire Gas System services approximately 1,200 propane gas distribution customers. Total purchase price for the New Hampshire Gas System was approximately U.S. $3.16 million, subject to certain closing adjustments.

### Transmission Group

#### (i) Northeast Supply Pipeline

In December 2015, the Transmission Group reached an agreement for acquiring an additional equity investment right in the Supply Link segment to the Northeast Expansion Pipeline, (the"Northeast Supply Pipeline") a joint venture with subsidiaries of Kinder Morgan. The project is a 30 inch greenfield pipeline from northeastern Pennsylvania to Wright, New York traversing 132 miles and having a design capacity of up to 1,200,000 dth/day. The Transmission Group has secured a 4% initial participation right, along with an option to increase its participation to 10%.

The Northeast Expansion Pipeline ("NEP Project") and the NSP Project developer, Tennessee Gas Pipeline Company, L.L.C., filed a combined FERC application for a Certificate of Public Convenience and Necessity ("CPCN") along with a complete Environmental Review in November 2015. A November 2016 FERC order has been requested and a November 2018 project in service date is planned.

## 2.3 Recent Developments - 2016

### Corporate

#### (i) Declaration of Canadian equivalent first quarter dividend of Cdn $0.1287 (U.S. $0.0963) per Common Share

On March 10, 2016, APUC announced that the Board of Directors of APUC declared the first quarter 2016 dividends of U.S. $0.0963 per common share. Based on the Bank of Canada noon exchange rate on the declaration date, the Canadian dollar equivalent for the first quarter 2016 dividends is set at Cdn $0.1287 per common share.

#### (ii) Pending Acquisition of The Empire District Electric Company

On February 9, 2016 APUC announced that through a wholly owned subsidiary it has entered into an agreement and plan of merger pursuant to which it will acquire Empire (NYSE:EDE) and its subsidiaries (the "Acquisition").

Under the terms of the all-cash transaction, which has been unanimously approved by the Board of Directors of each company, Empire's shareholders will receive U.S. $34.00 per common share (the "Purchase Price"), representing an aggregate purchase price of approximately $3.4 billion (U.S. $2.4 billion), including the assumption of approximately $1.3 billion (U.S. $0.9 billion) of debt as of September 30, 2015. The Purchase Price represents a 21% premium to the closing price on February 8, 2016 and a 50% premium to Empire's unaffected share price on December 10, 2015.

Closing of the Acquisition is subject to customary closing conditions, including the approval of Empire's common shareholders, and the receipt of certain state and federal regulatory and government approvals, including approval of the relevant commissions of the states of Arkansas, Kansas, Missouri and Oklahoma (collectively, the State Commissions), the Federal Communications Commission (the "FCC"), the Committee on Foreign Investment in the United States and the FERC, and the expiration or termination of the waiting period under the Hart-Scott-Rodino Act. The Transaction is expected to close in Q1 2017.

Empire is a Joplin, Missouri based regulated electric, gas (through its wholly-owned subsidiary The Empire District Gas Company), and water utility, collectively serving approximately 218,000 customers in Missouri, Kansas, Oklahoma, and Arkansas.

APUC expects the Acquisition will be accretive to earnings per common share in the first full year following closing and approximately 7% - 9% accretive to APUC's net earnings per common share over a three-year period following closing, excluding one-time acquisition-related expenses, and assuming a stable currency exchange environment. APUC also expects that the Acquisition will be approximately 12% - 14% accretive to Adjusted Funds from Operations per Common Share over a three-year period following closing, excluding one-time Acquisition-related expenses, and assuming a stable currency exchange environment. The Acquisition is expected to remain accretive to APUC's net earnings and cash from operating activities notwithstanding a scenario in which the Canadian dollar strengthens.

The Acquisition adds a large profitable regulated distribution and generation business, increasing APUC's scale, diversity of customers and geographies of service. APUC believes the increased contribution from regulated operations will further enhance the stability and predictability of Adjusted EBITDA, net earnings and quality of cash flows.

#### (iii) $1 Billion Bought Deal Offering of Convertible Unsecured Subordinated Debentures Represented by Instalment Receipts

On February 9, 2016, in connection with the acquisition of Empire, APUC and its direct wholly-owned subsidiary, LU Canada, entered into an agreement with a syndicate of underwriters (collectively, the "**Underwriters**") under which the Underwriters agreed to buy, on a bought deal basis, $1.0 billion aggregate principal amount of 5.00% convertible unsecured subordinated debentures ("Debentures") of APUC (the "Debenture Offering"). On March 9, 2016, the Underwriters exercised their option to purchase an additional $150 million of Debentures bringing the total amount of Debentures under the Debenture Offering to $1.15 billion.

All Debentures were sold on an instalment basis at a price of $1,000 dollars per Debenture, of which $333 dollars was paid on the closing of the Offering (the "First Instalment") and the remaining C$667 dollars (the "Final Instalment") is payable on a date (the "Final Instalment Date") to be fixed by APUC following satisfaction of all conditions precedent to the closing of APUC's acquisition of Empire.

See also *Convertible Unsecured Subordinated Debentures* in *Liquidity and Capital Reserves*.

#### (iv) U.S. $235 Million Term Credit Facility

Subsequent to the year end, Algonquin entered into a U.S. $235.0 million term credit facility with two U.S. banks. The proceeds of the term credit facility provide the company with additional liquidity for general corporate purposes and acquisitions. The facility matures on July 5, 2017.

### Distribution Group

#### (i) Acquisition of the Park Water System

On January 8, 2016, the Distribution Group closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility Park Water , now known as Liberty Utilities (Park Water) Corp. (the "Park Water System"). The acquisition of the Park Water was originally announced in September 2014. The Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

Total consideration for the utility purchase was U.S. $341.8 million, which includes the assumption of approximately U.S. $91.8 million of existing long-term utility debt. This acquisition maintains APUC's strategic business mix and further enhances its investment grade consolidated capital structure.

The water utility located in western Montana is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water. Please see ["Operational Risk Management - Regulatory Risk - Condemnation Expropriation Proceedings"] for a detailed description and discussion of the condemnation proceeding.

#### (ii) Successful Rate Case Outcomes

Subsequent to the year end, the Distribution Group concluded the New England Natural Gas and Peach State Natural Gas System rate cases which resulted in U.S. $11.0 million in increased rates. The full annualized impact of these rate cases will be realized in 2016

# 3. DESCRIPTION OF THE BUSINESS

## 3.1 Generation Group

### 3.1.1 Regulatory Regimes - Power Generation

#### (i) Canada

The electricity supplied within the Canadian provinces is primarily generated by government-owned corporations, such as Ontario Power Generation Inc. and Hydro-Québec. Independent power producers, such as APUC provide additional capacity and supply to the grids. In Canada, the provinces have legislative authority over the generation, transmission and distribution of electricity. This in turn means that each province may have different requirements for the business to comply with in respect of the projects it owns in each province.

Generally speaking, each province in which the Corporation operates has various pieces of legislation in effect with which the business must comply. These relate to the generation, transmission and distribution of electricity in the province, the administration of the electric system, as well as the creation and authority of various governmental agencies who have oversight of an aspect of the industry, such as the independent system operator (the "ISO") and the provincial energy board, utilities commission or other similar authority responsible for rate-making and regulatory oversight of the industry. In addition, some provinces require a generator of electricity to be licensed and registered with the appropriate governmental authority and the Corporation must comply with the conditions of license or registration accordingly. In addition to the legal requirements, the system operators have promulgated market rules to be complied with within their operating jurisdictions and any codes, rules and standards of the applicable energy board or utilities commission must be complied with.

#### (ii) United States

The power generation industry in the United States is regulated by theFERC under the U.S. Federal Power Act (“**FPA**”), Public Utilities Regulatory Policies Act (**PURPA**) and the Public Utility Holding Company Act of 2005 (“**PUHCA**”).

(1) Rate Regulation

All of APUC’s operating US power generation facilities are either: (1) exempt wholesale generators (“**EWGs**”); or (2) qualifying small power or cogeneration facilities (“**QFs**”). EWGs sell electricity exclusively in wholesale markets, while QFs with a power production capacity of 20 MW or less are exempt from most regulation under the FPA. There are two types of QFs: (1) qualifying small power production facilities; and (2) qualifying cogeneration facilities. In order to be a qualifying small power production facility, which includes hydro, geothermal, solar and biomass, the facility must meet the maximum size and fuel use criteria specified in FERC’s regulations. In order to be a qualifying cogeneration facility, the facility must meet the operating and efficiency criteria specified in FERC’s regulations. All APUC’s operating US power generation facilities that are EWGs possess FERC authorization to engage for sales for resale at market-based rates (“**MBR Authority**”). The QF with a capacity greater than 20 MW also possesses MBR Authority. QFs with a capacity of 20 MW or less are not required to possess MBR Authority for their power sales. MBR Authority is available to EWGs and certain QFs and is obtained by showing that the generator and its affiliates do not possess vertical or horizontal market power in the relevant market. Once MBR Authority is obtained, the EWG or QF with a capacity greater than 20 MW, may sell its power into the relevant market at market-based rates. Each entity with MBR Authority must detail its sales into the market by filing quarterly reports which details the relevant contracts used to sell power and the rates obtained for such power sales. QFs with a capacity of 20 MW or less are not required to file quarterly reports.

(2) PUHCA

APUC is also subject to the PUHCA. PUHCA and FERC's implementing regulations impose certain books, records and accounting requirements on public utility holding companies. APUC is a public utility holding company and subject to such regulations. The Generation Group's intermediate holding companies claims exemption from PUCHA under Title 18, Part 366.3 of the U.S. Code of Federal Regulations (CFR), which provides that a company that is a holding company solely by virtue of holding interests in QFs, EWGs and foreign utility companies is exempt from the books, records and accounting provisions of PUHCA and FERC's regulations. Should any of the EWGs or QFs cease qualifying for such status by no longer meeting the regulatory requirements for qualification, then the exemption would no longer apply. At that time, the books, records and accounting requirements, requiring use of the Uniform System of Accounts would then apply.

### 3.1.2 Description of Operations

#### Hydroelectric Generating Facilities

#### (i) Production Method

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as "**head**"), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a head pond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

#### (ii) Principal Markets and Distribution Methods

The principal markets in which APUC operates in Canada are Alberta, Ontario, New Brunswick and Québec. In the US, the principal market is Maine. The majority of generated hydroelectricity is conveyed from the relevant facility to the purchasers under the terms of long term PPAs. The electricity is generally transferred by transmission line from the generating facility to the delivery point for the purchaser, and it is distributed through the grid to end user customers of the purchaser. A summary of the PPAs for the Generation Group's Renewable Energy Division is set out in Schedule A.

(1) Alberta

The electrical power industry in Alberta is regulated by the Electric Utilities Act (Alberta) ("**EUA**"). The Power Pool of Alberta ("Alberta **Power Pool**") was established under the EUA to provide a competitive, real-time spot market for electric energy. The Alberta Power Pool is non-discriminatory and open to any generator, marketer, distributor, importer or exporter that satisfies the qualification requirements established under the EUA and the rules and codes of practice of the Alberta Power Pool.

The EUA has also established the Alberta Electric System Operator ("**AESO**") to operate and manage the Alberta Power Pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy in Alberta. The AESO is governed by an independent board appointed by the Alberta Minister of Energy.

The AESO spot market, or pool price, is determined by market forces. The AESO accepts offers to sell power and bids to buy power through its Energy Trading System. The AESO then dispatches electricity in accordance with an economic merit order based on the lowest cost offers to supply demand in real time. All energy traded through the Alberta Power Pool is financially settled each hour at a single spot market price.

Three categories of sellers are eligible to offer and sell electricity through the Alberta Power Pool: marketers, importers and independent power producers. There are also three categories of eligible purchasers who may bid to acquire electricity from the Alberta Power Pool: retailers, direct access customers and exporters.

(2) Ontario

The Ontario government develops the regulatory framework for wholesale and retail competition through the Ontario Energy Board (the "**OEB**"). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

The Ontario Electricity Financial Corporation ("OEFC") holds all rights, obligations and liabilities under, and purchases the energy generated by the Ontario facilities in which APUC has an interest pursuant to, the existing contracts. APUC's relevant subsidiary entities have also received a license to generate from the OEB as required by the *Ontario Energy Board Act, 1998* (Ontario).

(3) New Brunswick and Northern Maine

Effective October 1, 2013, the New Brunswick government amended the provincial Electricity Act (New Brunswick), which resulted in the re-amalgamation of the New Brunswick System Operator ("**NBSO**") with members of the New Brunswick Power Corporation ("**NB Power**"), a vertically-integrated group of companies, resulting in the transmission system operation functions of the NBSO being performed by NB Power's Transmission and System Operator division.

(4) Québec

Hydro-Québec is the primary electricity generator, transmitter, and distributor of electricity in the province of Québec; its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular large hydro, and supports the development of other technologies-such as wind energy and biomass.

With a total installed capacity of 36,643 MW (in 2014), Hydro-Québec provides a clean, renewable, and reliable supply of electricity to all Québecers. It also sells power on wholesale markets in northeastern North America. Hydro-Québec has been generating, transmitting and distributing electricity for over half a century. The company is a world leader in the field of hydroelectricity.

As a result of its vast hydropower resources, Hydro-Québec's electricity rates are among the lowest in North America.

Similar to Ontario, the Québec government develops the regulatory framework for wholesale and retail competition. Since 1991, Hydro-Québec has procured some of its power requirements from private producers on terms and rates negotiated with each producer. The province continues to introduce various programs to stimulate renewable power from hydroelectric and wind powered facilities as well as cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the Dam Safety Act (Quebec) pursuant to Bill C-93 ("**Bill C-93**") and corresponding regulations. Bill C-93 imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works. As a result of this legislation, APUC's Renewable Energy Division was required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased by APUC within the Province of Québec.

APUC currently estimates further capital expenditures of approximately $8.0 million related to compliance with the legislation. It is anticipated that these expenditures will be invested over a period of several years estimated approximately as follows:

| (all dollar amounts in $ millions) | Total | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| Future Estimated Bill C-93 Capital Expenditures | **8.0** | 4.6 | 2.6 | 0.5 | 0.3 |

The majority of these capital costs are associated with the Belleterre, Rivière-du-Loup, and St. Alban Hydro Facilities.

The Generation Group has been working with the provincial authorities to reclassify, decommission or remove several small dams upstream of the Belleterre hydroelectrical generating facility ( the "Belleterre Hydro Facility") that are not required for power generation. During the first quarter of 2015, four dams were declassified and removed from the centre d' expertise hydrique du Quebec (CEHQ)'s registry, while three others were reclassified to Class E (Very Low Consequence) dams, from higher classes. Upon the recommendation of third party engineers, the Generation Group is in discussion with the relevant government ministries to postpone the decommissioning work on these dams for five years to allow sufficient time to determine the new decommissioning requirements and develop new project plans.

Shore-based civil remedial work at the Rivière-du-Loup hydroelectrical generating facility ( the "Rivière-du-Loup Hydro Facility") was completed in 2015, while completion of the in-river work is anticipated in 2016.

The dam safety study and a detailed condition assessment for the St. Alban Hydro Facility have been completed. The Generation Group has been working with third-party engineers and regulators to finalize the remedial plan for the main dam. Remedial work is expected to occur in 2016 to 2017.

On May 18, 2014, the Donnacona Hydro Facility experienced ice damage during the spring thaw and has been shut down. The Generation Group had previously planned capital expenditures for the Donnacona Hydro Facility in 2015 and 2016 in the amount of $7.8 million. It has been determined, in consultation with its 3rd party engineers, that a dam re-build is required to return the facility to operation. The Generation Group has initiated temporary civil works in anticipation of a dam rebuild, with a target to complete the rebuild of 2017. Consequently, the Generation Group does not anticipate any near-term expenditures related to C-93 compliance of the existing structure.

In addition to the C-93 related dam remediation work, the Generation Group has implemented a dam condition monitoring program at some of the above facilities following recommendations specified in the dam safety reviews.

### (iii) Material Facilities

(1) Long Sault Hydro Facility

The **Long Sault Hydro Facility** is an 18 MW hydroelectric generating facility located on the Abitibi River, 19 kilometers north of the Town of Cochrane, in northern Ontario. The facility was commissioned on April 1, 1998.

The facility was developed by a joint venture between the LS Partnership and N-R Power Partnership ("Long Sault"). The facility is owned by the co-owning joint ventures ("**Co-Owners**") as tenants-in-common and not as joint tenants, with the Co-Owners each having an undivided 50% interest in the facility. The partners in the LS Partnership are Algonquin Power (Long Sault) Corporation Inc. and APCI Algonquin Power (Long Sault) Corporation Inc. is a wholly-owned subsidiary of APCI. APCI is a wholly-owned subsidiary of APCH. The partners in Long Sault are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There is a non-recourse loan outstanding which is secured against the facility and the Co-Owners' interest therein. See "Credit Agreements" below.

APUC's interest in the facility was originally acquired by way of subscribing to two notes from the original developers. The notes receivable have a face value of approximately $17 million and bear interest at 9%. APUC earns interest income on the notes and is entitled to 100% of any incremental after tax cash flows from the facility up to 2013, 70% of any incremental after tax cash flows from 2014 to 2027 and 62.5% of any incremental after tax cash flows thereafter. APUC also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

The facility is a "run of the river" facility, which means there is a continuous discharge of water from the facility with no storage and release of water. The powerhouse is an integrated structure, housing four 4,500 kilowatt pit turbine generating units.

Pursuant to the terms of the PPA, the Co-Owners sell power produced by the facility exclusively to the OEFC. The PPA terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC's total market cost.

The Co-Owners receive a monthly capacity payment when the facility delivers an average of at least 1,800 kilowatts of power delivered to the delivery point in each fifteen minute interval to OEFC during at least 85% or more of the on-peak period fifteen minute intervals for that month. The "**On-peak**" period is between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays, and "**Off-peak**" is the other remaining hours. Monthly energy in excess of 115% of target generation is subject to an additional payment.

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The annual water rental charge commenced in January 2008.

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner's interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the facility on their behalf for nominal consideration.

There is an outstanding senior loan against the facility in the amount of $34.8 million as at December 31, 2015. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("**Clarica**"), The Canada Life Assurance Company and the Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in January 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse to APUC and is secured by the facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. In 2008, APUC issued an irrevocable letter of credit in an amount of $1.2 million to replace the debt service escrow deposit.

APUC's interest in the Long Sault Hydro Facility is by way of subscribing to two notes from the original developers, which effectively entitles APUC to 100% of after tax cash flows of the facility up to 2013, 70% from 2014 to 2027 and 62.5% thereafter. APUC also has the right to acquire 58% of the equity in the facility at the end of the term of the notes in 2038.

(2) Côte Ste-Catherine Hydro Facility

The Côte Ste-Catherine Hydro Facility is a hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11.1 MW. The facility is owned by the Mont-Laurier Partnership.

The land and water rights necessary for the operation of the facility have been obtained by way of a lease agreement with the St. Lawrence Seaway Authority. In 2009, the water rights lease was renewed for a term of 21 years commencing March 1, 2009. Although the facility is located on a federal waterway, the Province of Quebec has asserted jurisdiction over the water rights to this facility and has also asserted a claim against a predecessor by amalgamation to APCH for payment of revenues paid to the federal authority. See " *Enterprise Risk Management- Operational Risks Management - Litigation Risks and Other Contingencies*".

(3) Mont-Laurier Hydro Facility

The Mont - Laurier Hydro Facility is a 2.7 MW hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont - Laurier, Québec. The Mont Laurier Hydro Facility is owned by the Mont-Laurier Partnership.

The facility is constructed on lands owned by the Mont-Laurier Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the Mont Laurier Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.

(4) Côte Ste-Catherine and Mont - Laurier PPAs - General

Each of the Côte Ste-Catherine and Mont - Laurier Hydro Facilities has a PPA with Hydro Québec under which all power generated by the facilities is sold to Hydro Québec. The standard Hydro Québec PPA stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec PPAs, if a facility produces less energy than the minimum, a penalty is payable to Hydro Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

Power purchase rates under the Hydro Québec agreements (other than for the Mont - Laurier and Côte Ste-Catherine Hydro Facilities) increase in accordance with the Consumer Price Index for the Montréal urban community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont - Laurier Hydro Facility is subject to a fixed annual escalation of 1.8%. The Côte Ste-Catherine Hydro Facility (Phase I) power purchase rate increases at a fixed annual index of 1.1% for the first four years and 1.8% thereafter.

(5) Tinker Hydro Facility

The Tinker hydroelectirc facility (the "**Tinker Hydro Facility**") is located 5 miles north of Perth-Andover, New Brunswick and is situated near the mouth of the Aroostook River. The facility consists of five hydro units and a 1 MW diesel generator; the total nameplate capacity of the station equals 34.0 MW. Historical gross generation from the station averages 140,000 MW-hrs per year. The Tinker Hydro Facility benefits from the flow regulation of the Millinocket storage dam and Squa Pan Hydro Facilities, both of which are also owned and operated by APCo.

As part of the generation assets in New Brunswick and Northern Maine, APUC owns an electrical transmission system consisting of 14.7 km of 69 kV transmission line facilities. These facilities are used to interconnect the Tinker Hydro Facility to the New Brunswick transmission network, provide transmission service to Perth Andover Electric Light Commission, and provide export/ import capacity between Maine and New Brunswick. As part of the recent filings under the Electricity Act (New Brunswick), Algonquin Tinker Genco sought two initiatives under Matter 256; to secure pre-authorization of a transformer upgrade and to establish an updated revenue requirement for the transmission service function. On September 25, 2015, the Energy Utilities Board of New Brunswick issued an order of pre-approval in Matter No. 256, authorizing the installation of an upgraded transformer by Algonquin Tinker GenCo at 100 MVA along with associated lines and breaker upgrades. Capital expenditures of approximately $ 8 million (CAD) are anticipated. The Board is currently reviewing the assembled record of its hearing in January 2016 to determine a revised revenue requirement for the transmission service function in the same docket.

The Tinker Hydro Facility supplies approximately 31,000 MW-hrs per year to the municipal utility of Perth-Andover under a PPA expiring in 2021. The remaining generation from the plant, approximately 109,000 MW-hrs per year, is sold to retail commercial and industrial customers in the Maine and New Brunswick markets, as well as energy and capacity to the Maine and New Brunswick electricity markets.

*Energy Marketing*

The primary business of the Energy Marketing Group is to market the output of the Tinker Hydro Facility and other owned assets of APUC which sell the energy they generate and any applicable environmental attributes less any associated transportation costs. Additionally, the group manages gas purchases for the Windsor Locks Thermal Facility, and supports the development of strategies for selling the power output of other facilities of APUC that are approaching the end of their PPA lives. The Energy Marketing Group provides energy to commercial and industrial customers in the Northern Maine and Southern Maine markets primarily by purchasing energy from the Tinker Hydro Facility. Based on historical long term average levels of hydroelectric energy generation, the Tinker Hydro Facility provides approximately 65% of the energy required to service the Northern Maine customers and provides a natural hedge on supply.

The Energy Marketing Group purchases additional energy and applicable environmental attributes from the market to supplement the purchases from the Tinker Hydro Facility in order to service its customer demand, and sells any excess generation to the market. Risk associated with this business is managed through the purchase of fixed volume/prices from the market. In addition, the Energy Marketing Group negotiates appropriate pricing with large retail and wholesale consumers in northern Maine to ensure risk associated with volatility of consumption by the consumer is mitigated.

The Energy Marketing Group is responsible for purchasing gas for the Windsor Locks Thermal Facility located in Connecticut.

(6) Dickson Dam Hydro Facility

The Dickson Dam Hydro Facility is located 20 kilometers west of the Town of Innisfail, Alberta. The facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the water flows of the Red Deer River. The facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by APOT.

APUC sells all of the power generated at the Dickson Dam Hydro Facility in the Alberta Power Pool. In addition, APUC has entered into a fixed financial hedge agreement with CP Energy Marketing L.P. running from May 15, 2012 through December 31, 2016 for variable monthly volumes. The Dickson Dam Hydro Facility hedge covers approximately 75% of the expected annual generation volume from the facility.

The Dickson Dam Hydro Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available water flows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favor of the Minister of Environment (Alberta) in connection with the Minister's water management objectives.

## Wind Power Generating Facilities

### (i) Production Method

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.

### (ii) Principal Markets and Distribution Methods

The principal markets for APUC's operational wind facilities in Canada are Manitoba for the St. Leon Wind Facilities, Saskatchewan for the Red Lily I and Morse Wind Facilities, and Quebec for the Saint. Damase Wind Project. The electricity generated by the wind turbines is transmitted via electrical collection lines to the facility substations for subsequent delivery to the transmission system of the purchaser, Manitoba Hydro-Electric Board ("**Manitoba Hydro**") in the case of the St. Leon Wind Facilities, Saskatchewan Power Corporation ("**SaskPower**") in the case of the Red Lily I and Morse Wind Facility, and Hydro Quebec in the case of the Saint. Damase Wind Project. The purchaser then distributes the electricity to its customers or to other endpoints via the grid. The principal markets for APUC's wind facilities in the United States are the PJM Interconnection LLC ("**PJM**") and Electric Reliability Council of Texas regional markets ("**ERCOT**").

(1) Manitoba

Historically, Manitoba Hydro had been exclusively responsible for the production of electricity in the province. Manitoba Hydro is a net exporter of electricity, mainly to Ontario and certain states of the United States. To date, the province has been able to utilize its large hydroelectric resources to satisfy internal and export requirements.

(2) Saskatchewan

Saskatchewan's electricity market remains under provincial government control and has not undergone any significant deregulation. SaskPower, the primary electricity utility in Saskatchewan, is wholly-owned by the province through the Crown Investments Corporation. SaskPower has set a target of 50% of generation capacity from renewables by 2030. As a result, SaskPower has a number of programs to encourage and solicit wind and other renewable power from independent producers.

(3) Quebec

Hydro-Québec's hydroelectric portfolio accounts for 99% of electricity mix, and as such, the utility has encouraged the development of wind projects in the province in recent years. Hydro-Québec's previous wind project calls for tenders have resulted in over 3,000 MW of wind capacity to be installed in the province. In addition, another 275 MW of wind are under construction and another almost 400 MW are planned.

(4) Illinois and Pennsylvania

PJM is one of ten regional transmission organizations ("**RTOs**") operating in North America. PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. Acting as a neutral, independent party, PJM operates a competitive wholesale electricity market and manages the high voltage electricity grid to ensure reliability for more than 60 million people.

(5) Minnesota

The Midcontinent Independent System Operator ("**MISO**") is an **ISO**, similar to an RTO, operating in fifteen U.S. states and the Canadian province of Manitoba. MISO assures consumers of unbiased regional grid management and open access to the transmission facilities through their functional supervision. MISO has interconnections with PJM, ERCOT, and other RTOs and ISOs. The fifteen states where MISO operates are: Arkansas, Illinois, Indiana, Iowa, Kentucky, Louisiana, Michigan, Minnesota, Mississippi, Missouri, Montana, South Dakota, North Dakota, Texas and Wisconsin.

(6) Texas

ERCOT, like PJM, is one of the ten RTOs operating in North America. ERCOT is the successor to the Texas Interconnect System and its region occupies the entire Texas interconnection which occupies nearly all of the state of Texas. Unlike the other major North American Electric Reliability Corporation ("NERC") interconnections, the high voltage transmission and energy market within the Texas interconnection is operated by ERCOT as essentially a single power system instead of as a network of cooperating utility companies. The portion of the electric grid in the State of Texas that is under the administration of ERCOT was – and remains – essentially unconnected to electrical grids in other states and, in the absence of "electricity in interstate commerce," does not fall under federal regulation. ERCOT is a membership-based, non-profit council that provides electric power to approximately 23 million people in Texas.

### (iii) Material Facilities

(1) St. Leon Wind Facility

The St. Leon Wind Facility is a 104 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is owned by St. Leon LP.

On September 18, 2007, the St. Leon Wind Facility achieved commercial operation pursuant to a turn-key construction contract dated November 12, 2004. In January 2010, APUC executed an operation and maintenance service agreement (an "O&M") with Vestas-Canadian Wind Technology, Inc. ("**Vestas**") whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon Wind Facility for approximately 20 years.

St. Leon LP and St. Leon GP have entered into a PPA with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Wind Facility is sold to Manitoba Hydro. As of June 17, 2006, the facility achieved commercial operation status under the PPA with Manitoba Hydro. The term of the PPA is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the PPA, security in an amount of $1.8 million is required. The security is fully funded using an irrevocable letter of credit.

St. Leon LP entered into a Wind Power Production Incentive agreement with the Ministry of Natural Resources - Canada which entitles the St. Leon Wind Facility to receive an incentive from the federal government of $10.00 per MW-hr to a maximum of $3.7 million annually for a period of ten years ending March 2016.

(2) St. Leon II Wind Facility

The St. Leon II Wind Facility is a 16.5 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg, adjacent to the St. Leon Wind Facility.

In July 2011, an affiliate of APUC executed a 25-year PPA with Manitoba Hydro in respect of the St. Leon II Wind Facility. As of July 1, 2012, the facility started generating revenues in accordance with its PPA. Under the terms of the PPA, operational security in the amount of approximately $0.3 million is required until 60 days after the expiry of the term or renewal term, as the case may be. The security is fully funded using an irrevocable letter of credit.

In July 2011, an affiliate of the Corporation executed an operation and maintenance service agreement with Vestas whereby Vestas provides operation, maintenance and repair services at a contracted rate to the St. Leon II Wind Facility for approximately 20 years.

(3) Red Lily I Wind Facility

The Red Lily I wind generation facility (the "**Red Lily Wind Facility**") is a 26.4 MW wind generating facility located 5 kilometers west of Moosomin, Saskatchewan. The Red Lily I Wind Facility consists of 16 Vestas V82 wind turbine generators. The equity in the Red Lily I Wind Facility is owned by an independent investor, Concord Pacific Group. The Corporation's investment in the Red Lily I Wind Facility is in the form of participation in a portion of the senior debt facility, and a subordinated debt facility to the Partnership. As at December 31, 2015, APUC had a senior debt investment in the facility of $11.6 million that bears interest at the rate of 6.31% per annum and a subordinated debt investment in the facility of $6.6 million that bears interest at the rate of 12.5% per annum. In addition to the loans extended by APUC, an additional $31.0 million of senior debt has been provided by a third party lender. On February 23, 2016, a second tranche of subordinated loan for an amount equal to $15.6 million was advanced by the APUC. The proceeds from this additional subordinated debt were used by the Red Lily I Wind Facility to repay Tranche 2 of the Partnership's senior debt, including APUC's portion.

APUC has the option to formally exchange its debt investment and fee interest in the project for a 75% equity interest, exercisable for a period of 90 days commencing on February 24, 2016. In addition to interest payments on its debt financing, APUC is entitled to certain supervisory fees.

On July 30, 2008, the Red Lily I Wind Facility entered into a PPA with SaskPower. The PPA term is 25 years from commencement of commercial operation which was February 23, 2011. The PPA also includes a 2% annual increase throughout the term of the agreement.

(4) Morse Wind FacilityThe Morse Wind Facility is a 23 MW wind powered electric generating facility located near Morse, Saskatchewan, approximately 180 km west of Regina.

The facility is comprised of approximately 10 turbines spread over three contiguous facilities and is expected to generate 104 GW-hrs of energy per year, with all energy from the project being sold to SaskPower pursuant to a 20 year PPA under the Green Options Partner Program.

Construction of the facility commenced in the third quarter of 2014 and the facility reached commercial operation on April 22, 2015 with all 10 turbines completed and selling power under the provisions of the PPA. (5) Saint- Damase Wind Project

The St. Damase Wind Project is a 24 MW wind energy facility located in the MRC of La Matapédia in the Gaspé Region of the Province of Québec, 440 km east northeast of Québec City, Québec.

In May 2011, Société en Commandite Fleur de les Éoliennes Saint-Damase executed a 20-year PPA with Hydro Québec in respect of the Saint - Damase Wind Project. Construction of the facility was completed on December 2, 2014 for a total net book value of generating assets of $64.2 million.

In November 2013, Société en Commandite Fleur de les Éoliennes Saint-Damase executed an Enercon Partner Konzept Agreement with Enercon whereby Enercon provides service and maintenance services at a contracted rate to the Saint-Damase Wind Project for 15 years.

Under the terms of the PPA, operational security in the amount of approximately $0.9 million is required, which has been fully funded using an irrevocable letter of credit.

The Saint - Damase Wind Project currently has outstanding senior and subordinated loans. The senior loan is in the amount of $27.3 million as at December 31, 2015. The senior loan was provided by a credit facility comprising third party members as arranged by APCo and carries a term of 20 years, maturing in December 2034, and bearing at an interest rate of 5.5%. The senior loan is interest only and payable semi-annually. Additionally, the project has subordinated loans totalling $38.0 million as at December 31, 2015. The subordinated loan is split into two tranches of $11.4 million and $26.6 million with the municipality of Saint - Damase and APT respectively. Each subordinated loan carries a term of 20 years, maturing in December 2034, and bears an interest rate of 10.0%. The loan is non-recourse to APUC and is secured by the facility and the ownership interests therein.

(6) Shady Oaks Wind Facility

The Shady Oaks Wind Facility is a 109.5 MW wind energy facility located in Lee County, Illinois, 80 km west of Chicago. The Shady Oaks Wind Facility is owned by GSG 6, LLC, an entity acquired by APFA from Goldwind on January 1, 2013.

GSG 6, LLC is party to a fixed price Service and Maintenance Agreement with an affiliate of Goldwind, the original equipment manufacturer, whereby the affiliate provides turbine operation, maintenance and repair services at a contracted rate to the Shady Oaks Wind Facility for the duration of the warranty period under the project turbine supply agreement, which is approximately 20 years.

GSG 6, LLC has entered into a 20 year power sales contract with the largest electric utility in the state of Illinois, Commonwealth Edison. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. Annual production is subject to contingent curtailment based on certain regulatory constraints of the electricity purchaser. The remaining generation and associated RECs are sold into the market. The Shady Oaks Wind Facility reached commercial operation in June 2012. Under the terms of the power sales contract, GSG 6, LLC is required to provide security in the amount of US$4.7 million, which APFA has provided via a letter of credit.

(7) Sandy Ridge Wind Facility

The Sandy Ridge Wind Facility is a 50 MW wind energy facility located near Tyrone, Pennsylvania, 180 km east of Pittsburgh. The Sandy Ridge Wind Facility is owned by Sandy Ridge Wind, LLC. APFA indirectly owns 100% of the managing ownership interests in Sandy Ridge Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Sandy Ridge Wind, LLC, Gamesa and Sandy Ridge Wind, LLC entered into an asset management and balance of plant operations and service agreement ("**AMBOSA**") under which Gamesa provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement under which turbine operation, maintenance and repair services are provided at a contracted rate to the Sandy Ridge Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

Sandy Ridge Wind, LLC is party to a long term energy production hedge ("**Primary Energy Production Hedge**") with J.P. Morgan Ventures Energy Corporation ("**JPMVEC**"), a wholly owned subsidiary of J.P. Morgan, having a term of 10 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 72% of energy revenues are expected to be earned under an Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the energy market in which the Sandy Ridge Wind Facility is registered.

(8) Minonk Wind Facility

The Minonk Wind Facility is a 200 MW wind energy facility located near Minonk, IL, 200 km southwest of Chicago, IL. The facility is owned by Minonk Wind, LLC. APFA indirectly owns 100% of the managing ownership interests in Minonk Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Minonk Wind, LLC, Gamesa and Minonk Wind, LLC entered into an AMBOSA under which Gamesa provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement, under which turbine operation, maintenance and repair services are provided at a contracted rate to the Minonk Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

Minonk Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 10 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 73% of energy revenues are expected to be earned under an Energy Production Hedge. Ancillary services, including capacity and RECs, are sold into the energy market in which the Minonk Wind Facility is registered.

(9) Senate Wind Facility

The Senate Wind Facility is a 150 MW wind energy facility located near Graham, Texas, 200 km west of Dallas, Texas. The Senate Wind Facility is owned by Senate Wind, LLC. APFA currently indirectly owns 100% of the managing ownership interests in Senate Wind, LLC through WP SponsorCo.

As part of APFA's acquisition of a controlling interest in Senate Wind, LLC, Gamesa and Senate Wind, LLC entered into an AMBOSA, under which Gamesa provides asset management and balance of plant operations to the owner for a period of 20 years, and an operations and maintenance agreement under which turbine operation, maintenance and repair services are provided at a contracted rate to the Senate Wind Facility for a period of 17 years beyond the 3 year warranty period outlined in the facility's turbine supply agreement.

Senate Wind, LLC is party to a Primary Energy Production Hedge with JPMVEC, having a term of 15 years beginning January 1, 2013. Based on the JPMVEC contract quantity, approximately 64% of energy revenues are expected to be earned under an Energy Production Hedge. RECs are sold into the energy market in which the Senate Wind Facility is eligible to sell such products.

### (iv) Renewable Energy Credits

**RECs** are tradable commodities representing the generation of 1 MW-hr of electricity, and are used by utilities to satisfy compliance with Renewable Portfolio Standards ("**RPS**") where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time the Minonk, Sandy Ridge, Senate, and Shady Oaks Wind Facilities each produce and sell RECs through bilateral contracts.

## Solar Power Generating Facilities

### (i) Production Method

Solar power is the conversion of sunlight into electricity, either directly using photovoltaics or indirectly using concentrated solar power. APUC's solar generation facilities, the Cornwall Solar Project, and Bakersfield I Project utilize photovoltaics which convert light into electric current using the photovoltaic effect. The array of a photovoltaic power system produces direct current ("**DC**") power which fluctuates with the sunlight's intensity. For practical use, commercial installations convert this DC generated power to alternating current ("**AC**"), through the use of inverters. Multiple solar cells are connected inside modules. Modules are wired together to form arrays, then connected to an inverter, which produces power at the desired voltage/frequency/phase.

### (ii) Principal Markets and Distribution Methods

The principal market for APUC's operational solar facility in Canada is Ontario for the Cornwall Solar Facility, and California for the Bakersfield I Solar Facility. The electricity generated by the solar panels is transmitted via electrical collection lines to the facility substation for subsequent delivery to the distribution/transmission system under control of the local distribution company and the ISO.

(1) Ontario

The IESO was merged with the OPA in 2015. The combined organization operating as the IESO is an independent, non-profit corporation that is responsible for the real time operation, long term planning and procurement for Ontario's electricity system. The IESO is licensed by the OEB, it reports to the Ontario legislature through Ontario's Ministry of Energy.

(2) California

The California Independent System Operation ("**CAISO**") was formed in 1998 following a restructuring of the state electricity markets, and at the recommendation of the FERC. The CAISO operates as a non-profit public corporation responsible for operating the wholesale power system, maintaining the reliability of the grid, and planning for future demands. It is regulated by FERC.

### (iii) Material Facilities

(1) Cornwall Solar Project

The Cornwall Solar Project is a 10 MW ground mounted photovoltaic solar energy facility located near Cornwall, Ontario, 100 km southeast of Ottawa.

On March 27, 2014, the Cornwall Solar Project achieved commercial operation pursuant to the FIT contract between the project and the OPA (now the IESO). The term of the PPA is 20 years with a fixed power purchase rate throughout the term.

(2) Bakersfield I Solar Project

The Bakersfield I Solar Project is a 20 MW ground mounted photovoltaic solar energy facility that uses single axis trackers to optimize the site's generating efficiency. The site is located near Bakersfield, California, 150 km northwest of Los Angeles.

The Bakersfield I Solar Project achieved commercial operation in April 2015, generating fixed-price revenues via a 20 year Power Purchase Agreement with PG&E.

## Thermal (Cogeneration) Electric Generating Facilities

### (i) Production Method

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel's energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel's energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel's energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

### (ii) Principal Markets and Distribution Methods

The principal markets of APUC's cogeneration facilities are California and Connecticut. The electricity produced from these facilities is conveyed from the relevant facility to the electricity markets either under the terms of long-term contracts or according to ISO rules. In addition to grid sales of electricity and power, electricity and thermal energy is also sold to onsite or adjacent third party thermal host facilities for use in production.

#### (1) California

The electric transmission system and wholesale markets in California are primarily regulated by the California Public Utilities Commission ("CPUC") and FERC. The CAISO administers the wholesale electricity marketplace for the region.

#### (2) Connecticut

The electricity markets and transmission systems in Connecticut are governed by the Independent System Operator New England ("**ISO-NE**"). ISO-NE was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region's electric bulk power generation and transmission systems and administering the region's open access transmission tariff ("OTAA").

Since May 1, 1999, ISO-NE has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an internet-based market system.

### (iii) Material Facilities

#### (1) Sanger Thermal Facility

The Sanger thermal cogeneration facility (the "**Sanger Thermal Facility**") is a 56MW natural gas-fired generating facility located in Sanger, California. The facility is a combined cycle generating station comprised of a 44 MW General Electric LM6000 PC Sprint gas turbine, commissioned in 2008, and a 12.5 MW Westinghouse steam turbine, originally commissioned in 1991. In 2012, APUC successfully completed a major upgrade at the Sanger Thermal Facility that involved an overhaul of the steam turbine, the replacement of the steam turbine generator, and the installation of a new 115kV transformer sized to manage the full output of the facility. The Sanger Thermal Facility is owned by Sanger LLC, a subsidiary of APFA.

Output of the Sanger Thermal Facility is governed by the terms and conditions of a firm capacity and energy PPA with PG&E. The agreement has a term of 30 years, expiring in 2021, and calls for delivery of 38 MW of firm capacity.

Natural gas for the facility is delivered under the terms of a gas supply agreement with Constellation NewEnergy, Inc. for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Gas above or below the nomination requirement can be bought or sold at the applicable spot prices.

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Sanger LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the Sanger Thermal Facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

#### (2) Windsor Locks Thermal Facility

The Windsor Locks thermal cogeneration facility (the "Windsor Locks Facility") has a total installed capacity of 71 MW. The facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine both commissioned in 1990, and a 15 MW Solar Titan 130 combustion turbine installed in 2012. The Windsor Locks Thermal Facility is owned by Windsor LLC.

The Windsor Locks Thermal Facility supplies thermal steam energy and the majority of the output from the Solar Titan combustion turbine to Ahlstrom, a leading paper and non-woven materials manufacturer, pursuant to a ground lease and an Energy Services Agreement (the "**ESA**"). Pursuant to the ESA, Ahlstrom leases the facility site to Algonquin Power Windsor Locks LLC and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Thermal Facility for use at its specialty fibers composites mill located adjacent to the Windsor Locks Thermal Facility. Payments under the ESA are fully indexed to the cost of natural gas consumed by the Windsor Locks Thermal Facility.

With the current configuration, 90% of the output of the baseload electrical generation is generated by the Solar Titan combustion gas turbine and is sold to Ahlstrom. The additional installed capacity at the site is committed to the ISO-NE market in the day ahead energy market, and the capacity and reserve markets as appropriate. Each MW generated by the Solar Titan combustion turbine qualifies for the production of RECs.

APUC's subsidiary, Algonquin Power Windsor Locks LLC, has entered into an agreement with a natural gas retailer and wholesale supplier to provide gas to the Windsor Locks Thermal Facility as required to meet the Ahlstrom ESA obligations and the market dispatch requirements.

#### (iv) Renewable Energy Credits

RECs are tradable commodities representing the generation of 1 MW-hr of electricity, and are used by utilities to satisfy compliance with **RPS** where necessary. These RPS mandates are set at a state level, and stipulate a certain amount of electricity to be generated from renewable sources by a specific year. These targets range from 10-40%, with some initial deadlines having already passed, and some stretching to 2025 and beyond. At the current time the Windsor Locks Thermal Facility produces and sells RECs through bilateral contracts.

### Business Development

#### (i) Strategy

The Generation Group's Development Division works to identify, develop and construct new, renewable and efficient power generating facilities, as well as to identify, develop and construct other accretive projects that maximize the potential of APUC's existing facilities. Development is focused on projects within North America with a commitment to working proactively with all stakeholders, including local communities. It utilizes existing industry relationships to assist in the identification, evaluation, development and construction of projects, and retains expertise, as required, from the financial, legal, engineering, technical, and construction sectors. APUC's approach to project development is to maximize the utilization of internal resources while minimizing external costs. This allows development projects to evolve to the point where most major elements and uncertainties of a project are quantified and resolved prior to the commencement of project construction. Major elements and uncertainties of a project include the signing of a PPA, obtaining the required financing commitments to develop the project, completion of environmental permitting, and fixing the cost of the major capital components of the project. It is not until all major aspects of a project are secured that construction will proceed.

The prevailing economic climate has also created opportunities to acquire operating assets or third party development projects at various stages of development on terms that require the experience and financial resources that the Corporation has at its disposal. The strategy is to focus on high quality renewable and high efficiency thermal energy generation projects that benefit from low operating costs using proven technology that can generate sustainable and increasing operating profit in order to achieve a high return on invested capital.

#### (ii) Principal Market Environment

APUC believes that future opportunities for power generation projects will continue to develop as new targets are set for renewable and other clean power generation projects.

Within Canada, the market is driven largely by provincial regulations, of which Ontario and Saskatchewan are expected to present the most immediate opportunities for the corporation. However, the AESO has been commissioned to develop recommendations for the procurement of renewable sources of power that will allow the province to meet its objective to have 30 per cent of electricity generation by 2030 come from renewable sources. The recommendations are to be published by May in the hope of having the first project approved by the government by end of the 2016. The Ontario government, through the **IESO** is conducting a process to receive Requests For Proposals ("**RFPs**") for up to 300 MW of wind power, up to 140 MW of solar power and up to 50 MW of hydro power with responses due on March 9th 2016. A second RFP is anticipated to be issued by the Ontario IESO in early 2017, but the scale and scope has yet to be published. Nova Scotia also continues to offer its community FIT program, albeit on a smaller scale.

Within the United States, the most notable stimulus for the development of renewable power is the federal renewable electricity production tax credit ("**PTCs**" or "**Production Tax Credits**"), a per-kilowatt-hour tax credit for electricity generated by qualified energy resources, and the federal investment tax credit ("**ITCs**" or "**Investment Tax Credits**"), a tax credit for qualified renewable energy facilities based upon a percentage of eligible capital costs. On December 18th, 2015, the United States Congress approved a five-year extension to the 30 percent ITC for solar energy properties and 2.3 cents per kilowatt-hour PTC for wind facilities. The ITC for solar energy will remain at 30 percent through 2018, before it phases down gradually to 10 percent in 2022. The PTC for wind energy will be at maintained at 2.3 cents in 2016 before phasing down 60 percent by 2020. Additionally, other incentives continue to be offered independently for the development of renewable sources of power at the state and local levels. State policies continue to be driven by RPS, which vary between states. As of September 2014, 30 states have adopted binding RPS targets, and 9 have taken on voluntary targets. These targets range between 10% and 40% of installed capacity or retail sales, to be achieved between 2015 and 2028.

APUC will continue to pursue development projects which provide the opportunity to exhibit accretive growth within these markets.

### (iii) Current Development Projects

The Generation Group's Development Division has successfully completed, is constructing and is developing a number of power generation projects. The projects are as follows:

| Project Name | Location | Size (MW) | Estimated Capital Cost (millions) | Commercial Operation | PPA Term | Production GW-hrs |
|---|---|---|---|---|---|---|
| **Total Projects in Construction** | | | | | | |
| Odell Wind Project[1] | Minnesota | 200 | $ 446.8 | 2016 | 20 | 814.7 |
| Val Eo Wind Project[2] | Quebec | 24 | $ 70.0 | 2016/17 | 20 | 66.0 |
| Bakersfield II Solar Project[3] | California | 10 | $ 37.4 | 2016 | 20 | 24.2 |
| Deerfield Wind Project[4] | Michigan | 150 | $ 419.4 | 2016 | 20 | 555.2 |
| Great Bay Solar Project[5] | Maryland | 75 | $ 249.1 | 2016/17 | 10 | 152.0 |
| | | **459** | **$ 1,222.7** | | | **1,612.1** |
| **Projects in Development** | | | | | | |
| Amherst Island Wind Project | Ontario | 75 | $ 272.5 | 2017 | 20 | 235.0 |
| Chaplin Wind Project | Saskatchewan | 177 | $ 340.0 | 2017/18 | 25 | 720.0 |
| **Total Projects in Development** | | **252** | **$ 612.5** | | | **955.0** |
| **Total in Construction and Development** | | **711** | **$ 1,835.2** | | | **2,567.1** |

1 Total cost of the project is expected to be approximately $322.8 million in U.S. dollars.

2 Size, Estimated Capital Costs, Commercial Operation Date, PPA Term and Production refer solely to Phase I of the Val-Eo Wind Project.

3 Total cost of the project is expected to be approximately $27.0 million in U.S. dollars.

4 The total cost of the project is expected to be approximately $303.0 million in U.S. dollars

5 The total cost of the project is expected to be approximately $180.0 million in U.S. dollars.

#### (1) Odell Wind Project

The Odell Wind Project is a 200 MW wind development located in Cottonwood, Jackson, Martin, and Watonwan counties in Minnesota and is being constructed on approximately 23,000 acres of leased land.

The project will utilize 100 Vestas V110-2.0 wind turbines. Pursuant to a 20-year PPA, all energy, capacity and renewable energy credits from the project will be sold to Northern States Power Company, a subsidiary of Xcel Energy Inc., which is a diversified utility operating in the midwest U.S.

Construction of the project began in the second quarter of 2015, with total costs to complete estimated at U.S. $322.8 million. Turbine erection began in early November and the new 115 kV transmission line has been built. The collection system substation work was completed and successfully energized in cooperation with the Transmission Provider in December 2015.

It is anticipated that the Odell WindProject will qualify for U.S. federal production tax credits, accordingly the project company has entered into a partnership agreement with third parties (tax equity) to contribute approximately $180 million USD to the project in return for the majority of the tax attributes. Construction financing including a portion that bridges to tax equity's investment was arranged by the project company during 2015.

The Generation Group's participation in the project will be via a 50% equity interest in a new joint venture with a third party developer. The Corporation is accounting for the joint venture as an equity method investment since both partners have joint control of the new venture. The Generation Group holds an option to acquire the other 50% interest on commencement of commercial operations, which is expected in the second quarter of 2016.

(2) Val-Éo Wind Project

The Val-Éo Wind Project is a 125 MW project located in the local municipality of Saint-Gideon de Grandmont, which is within the regional municipality of Lac-Saint-Jean-Est. The project proponents include the Val-Éo wind cooperative formed by community based landowners and the Generation Group.

The Val Eo Wind Project is being developed in two phases: Phase I of the project (24 MW) is expected to be erected in 2016 comprised of eight wind turbines, producing approximately 66.0GWh annually. The second phase of the project would entail the development of an additional 101 MW and would be constructed following evaluation of the wind resource at the site, completion of satisfactory permitting and entering into appropriate energy sales arrangements.

Pursuant to a 20-year PPA, all energy from Phase I of the project will be sold to Hydro Quebec.

All land agreements, construction permits, and authorizations have been obtained for Phase I. After the permitting process was delayed at the provincial level, construction planned in 2015 has been re-evaluated due to the severe weather conditions in the region. The new schedule calls for construction to begin in the second quarter of 2016 as such the project is expected to now reach commercial operations in 2017.

The Generation Group's equity interest in the project is subject to final negotiations with the Val-Éo community cooperative but, in any event, will not be less than 25%. It is believed that the first 24 MW phase of the Val-Éo Wind Project will qualify as CRCE and therefore the project will be entitled to a refundable tax credit equal to approximately $18.0 million.

(3) Bakersfield II Solar Project

The Bakersfield II Solar Project is a 10 MW project adjacent to the Generation Group's 20 MW Bakersfield I Solar Project in Kern County, California, which is currently under construction.

The 10 MW Bakersfield II Solar Project executed a 20 year PPA on September 22, 2014 with a large California based electric utility. The project will be located on 64 acres of land adjacent to the 20 MW Bakersfield I Solar Project.

The total project cost for Bakersfield II Solar of approximately U.S. $27.0 million is expected to be funded with a combination of senior debt, common equity, and contributions from tax equity investors. Consistent with financing structures utilized for U.S. based renewable energy projects including the Bakersfield I Solar Project, it is anticipated that the Bakersfield II Solar Project will source financing in the amount of approximately 40% of the capital costs from certain tax equity investors.

Construction of the project is underway, project permits with the county and a EPC contractor are advanced. The project has a commercial operations targeted for second quarter of 2016.

(4) Deerfield Wind Project

The Deerfield Wind Project is located in central Michigan and is being constructed on approximately 20,000 acres of land leased from a supportive wind power land owner group. The Generation Group's interest in the project is via a 50% joint venture with the original developer. The Generation Group holds an option to acquire the other 50% interest for total contributions, subject to certain adjustments that are 90 days following commencement of operations.

The project will utilize 44 Vestas V110-2.0 wind turbines and 28 Vestas V110-2.2 turbines and is estimated to generate 555.2 GWhr annually. The Deerfield Wind Project has a 20 year power purchase agreement with a local electric distribution utility serving approximately 260,000 customers in Michigan.

At the end of year, over 90% of the private land access roads had been constructed and public road improvements are underway. The main power transformer procurement has been finalized, and engineering for the project is nearing completion.

The total project cost is expected to be approximately U.S. $303 million. It is anticipated that the Deerfiled Wind Project will qualify for U.S. federal production tax credits, accordingly, approximately 50% of the permanent project financing is expected to be funded by tax equity investors in return for the majority of the tax attributes.

The project is expected to achieve commercial operation at the end of 2016 with its first full year of operation beginning 2017.

(5) Great Bay Solar Project

The Great Bay Solar Project is located in Somerset County in southern Maryland. The project was acquired by the Generation Group in late 2015.

The project has a 10 year PPA with the US Government Services for all energy output from the facility, with a 10 year extension option. Solar RECs from the project will be retained by APUC, to be sold into the Maryland market. The expected annual generation will be 152.0 GWh.

Permitting with the county is underway, and expected to be completed in Q2 2016. The project has received its CPCN and Necessity from the State of Maryland Public Service Commission. The EPC contract has been executed, and equipment procurement is in progress, with deliveries to site beginning in Q3 2016. The commercial operations date is currently expected in late 2016 or early 2017.

The Generation Group expects the project will qualify for U.S. Investment Tax Credits and accordingly, approximately U.S. $62 million of the permanent project financing is expected to be funded by tax equity investors in return for the majority of the tax attributes.

(6) Amherst Island Wind Project

The Amherst Island wind generation facility (the "Amherst Island Wind Project") is located on Amherst Island near the village of Stella, approximately 15 kilometers southwest of Kingston, Ontario. In February 2011, the 75 MW project was awarded a FIT contract by the OPA as part of the second round of the OPA's FIT program.

The Amherst Island Wind Project is currently contemplated to use Class III wind turbine generator technology. The available wind resource is forecast to produce approximately 235 GWh of electrical energy annually, depending upon the final turbine selection for the project. Final negotiations on the turbine supply agreement is ongoing. Total capital costs for the facility are currently estimated to be $272.5 million, and engineering, procurement and construction contractor selection is underway. The financing of the project will be arranged and announced when all required permitting and all other pre-construction conditions have been satisfied.

The Renewable Energy Approval ("REA") was issued on August 24, 2015 following 29 months of review by the Ontario Ministry of Environment. An appeal of the REA has been made to the Environmental Review Tribunal ("ERT"). The appeal process is generally limited to a period of 6 months, although the ERT may grant extensions in appropriate cases. It is anticipated that the hearing will extend beyond 6 months and is likely to conclude in April 2016. Other permitting processes, and the engineering and procurement of long-lead equipment are progressing according to schedule including the supply of turbines for the project. The project has a planned construction time frame of approximately 12 months.

(7) Chaplin Wind Project

In the first quarter of 2012, the Generation Group entered into a 25 year PPA with SaskPower for development of a 177 MW wind power project (the "Chaplin Wind Project") in the rural municipality of Chaplin, Saskatchewan, 150 km west of Regina, Saskatchewan.

The Chaplin Wind Project will be developed in two phases: Phase I of the project , which comprises approximately 35 MW of the total project, will be erected and operational in 2017. Phase II of the project, which comprises the remaining approximately 142 MW, will be the infill construction phase and will only proceed following evaluation of the wind resource at the site, and completion of satisfactory permitting.

The total capital expenditures and energy costs will vary depending on turbine selection. Depending on the size of the turbines used the number of pads will vary from 58 to 70, and energy may vary from 659-766 GWh. Final selection will be based on multiple factors including an assessment of the internal rate of return. The total facility will be constructed at an estimated capital cost of $340.0 million but will vary with energy depending on final turbine selection.The 25 year PPA features a rate escalation provision of 0.6% throughout the term of the agreement. The project will take advantage of its favorable location by interconnecting with a nearby 138kV line and will be compliant with SaskPower's latest interconnection requirements.

In the first quarter of 2015, the Environmental Impact Statement documentation was submitted and meetings were held with the Ministry of Environment ("SKMOE"). Supplemental reports were submitted in the second and third quarters of 2015. The SKMOE completed the required 30 day public posting period on November 17, 2015, and the Environmental Impact Assessment (EIA) is expected to be issued in the first quarter of 2016. The turbine and balance of plant contractor selection will be finalized upon signing of the turbine supply agreement, which is in the final stages, though dependent on the SMKOE permit approval.

### (iv) Future Development Projects – Greenfield Projects

The company continues to pursue new development opportunities as well as build upon an existing portfolio of green-field sites. These projects represent a diversified range of opportunities within hydro, solar, wind and natural-gas modes of generation and are located throughout North America.

### 3.1.3 Specialized Skill and Knowledge

The Generation Group's employees, also have extensive experience and contacts in the independent power industry in Canada and the United States. The energy from hydrology aspect of the business of the Generation Group requires specialized knowledge of hydraulic turbines and their various components. This specialized knowledge is available to the Generation Group in-house.

The energy from wind aspect of the business of the Generation Group requires specialized knowledge of wind turbines and their various components. This specialized knowledge is available to the Generation Group in-house. On a more general level, the production of energy from all facilities of the Generation Group requires specialized skill and knowledge, and the Generation Group has employed various personnel who have such skill and knowledge.

### 3.1.4 Competitive Conditions

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind, water, and solar. With deregulation and opening of competition in the electricity marketplace, there should be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

The US Department of Energy ("**USDOE**") has suggested that in a competitive marketplace, utilities and energy marketers will utilize green power pricing to strengthen their image with their customers and build customer loyalty. Further, the USDOE has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The USDOE believes that as deregulation and open competition evolve, the green power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation. Additionally, programs and policies are evolving at all government levels, allowing for the trading of greenhouse gas credits created by renewable energy projects to be seen as part of the eventual solution.

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric, wind and solar power is not subject to commodity fuel price volatility or risk. In addition, generation of the above forms of power generation do not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Taking into account capital costs, wind and solar power has generally been more expensive than traditional forms of generated power. However, in recent years costs have decreased with the increased demand for renewable energy, market competitiveness and improvements in generating technology. With production tax incentives, investment tax incentives, RPS, and improved equipment capacity factors, both wind and solar energy have achieved parity with market pricing for electricity in many jurisdictions.

APUC believes that future opportunities for power generation projects will continue to arise given that many jurisdictions, both in Canada and the United States, continue to increase targets for renewable and other clean power generation projects. APUC is ideally positioned to take advantage of this demand for increased renewable energy, given that a significant portion of its assets are from renewable sources. It has experience and knowledge in the area. APUC will continue to actively pursue development projects which provide the opportunity to exhibit accretive growth. APUC anticipates its involvement in many future opportunities as initiatives designed to support independent power producers are being supported by virtually every Canadian province and a significant number of U.S. States.

### 3.1.5 Cycles & Seasonality

#### (i) Hydroelectric Generating Facilities

The Generation Group's hydroelectric operations are impacted by seasonal fluctuations and year to year variability of the available hydrology. These assets are primarily "run-of-river" and as such fluctuate with natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. Year to year the level of hydrology varies impacting the amount of power that can be generated in a year.

#### (ii) Wind Power Generating Facilities

The Generation Group's wind generation facilities are impacted by seasonal fluctuations and year to year variability of the wind resource. During the spring and fall periods, winds are generally stronger than during the summer periods. The ability of these facilities to generate income may be impacted by naturally occurring changes in wind patterns and wind strength.

#### (iii) Energy Marketing of the Tinker Generating Facility

Demand for energy sold to retail customers in the Maritime region is primarily affected by temperature. Demand for energy during colder months is generally greater than warmer months as the load served is located in a "winter peaking" region.

#### (iv) Solar Power Generating Facilities

The Generation Group's solar generation facilities are impacted by seasonal fluctuations and year to year variability in the solar radiance. For instance, there are more daylight hours in the summer than there are in the winter resulting in higher production in the summer months. The ability of these facilities to generate income may be impacted by naturally occurring changes in solar radiance.

### 3.1.6 Customers

The Generation Group's businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2015, APUC's businesses' revenues were derived as follows: Manitoba Hydro - 3.0% PJM - 2.9%;; Hydro Quebec – 2.7%; PG&E - 2.1%; and Ahlstrom - 1.6%.

## 3.2 Distribution Group

### 3.2.1 Regulatory Regimes - Utility Distribution Systems

Investor-owned utilities, whether water distribution and waste water collection systems, electric distribution systems or gas distribution systems, are generally subject to economic regulation by the public utility commissions of the states in which they operate. The respective public utility commissions typically have jurisdiction over rates, service, accounting procedures, issuance of securities, acquisitions and other matters. The utilities generally operate under cost-of-service regulation as administered by these state authorities, using a test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base and deemed capital structure, together with all reasonable and prudent costs, establishes the revenue requirement upon which each utility's customer rates are determined. Rates charged by these utilities are determined such that rates are set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 8% to 12%. This oversight and other rules set by the state utility commissions are intended to ensure adequate supplies of water, electricity and natural gas together with financial security, transparency in the rate setting process and reasonable prices.

#### (i) Water Distribution and Waste Water Collection Systems

Generally, water and wastewater providers in the United States operate as geographic monopolies within the areas in which they serve. A water or wastewater company is typically provided a service territory defined by a Certificate of Public Convenience and Necessity ("**CPCN**") which imposes an exclusive right and duty to serve in the service territory. A CPCN is typically granted by a State agency, which also serves as an economic and service quality regulator for these water or wastewater service providers. Such agencies are charged with ensuring that water and wastewater services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the utility customers as well as companies and their shareholders. Rates are approved by the agency to provide the water or wastewater company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

#### (ii) Electric Distribution Systems

The electricity industry is highly regulated in the United States. The industry is regulated under strict standards at multiple levels - federal, state and sometimes local. Under the FPA, FERC regulates interstate transmission, wholesale sales of electricity, corporate acquisitions and dispositions, securities and debt issuances, debt acquisitions, and reliability. State utility commissions perform a similar role, regulating sales of electricity to end-use customers, as well as financial stability and reliability.

Generally, electricity distribution companies in the United States operate as geographic monopolies within the areas in which they serve. An electricity distribution company is typically provided a CPCN which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these electric service providers. Such agencies are charged with ensuring that electric services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the electric service company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

### (iii) Natural Gas Distribution Systems

The natural gas industry is regulated at multiple levels - federal, state and sometimes local. Under the U.S. Natural Gas Act, FERC regulates interstate transmission and wholesale sales of gas. Interstate pipeline safety is regulated by the Department of Transportation. State utility commissions regulate retail distribution and sales of natural gas and intrastate pipelines. The federal pipeline safety requirements are often adopted by the state utility commissions and applied to intrastate pipelines and local distribution companies.

Generally, natural gas distribution companies in the United States operate as geographic monopolies within the areas in which they serve. A natural gas distribution company is provided a service territory which imposes an exclusive right and duty to serve in the service territory. The approval to serve is typically granted by a State agency, which also serves as an economic and service quality regulator for these natural gas service providers. Such agencies are charged with ensuring that natural gas services are provided at reasonable rates and quality to the Corporation's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the natural gas utility the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

## 3.2.2 Description of Operations

### Water Distribution and Waste Water Collection Systems

### (i) Method of Providing Services and Distribution Methods

A water utility services company provides regulated utility water supply and/or wastewater collection and treatment services to its customers.

A water utility sources, treats and stores potable water and subsequently distributes it to its customers through a network of buried pipes (distribution mains). A wastewater utility collects wastewater from its customers and transports it through a network of collection pipes, lift stations and manholes to a centralized facility where it is treated, rendering it suitable for discharge to the environment or for reuse, usually as irrigation.

The raw water for human consumption is sourced from the ground and extracted through wells or from surface waters such as lakes or rivers. The water is treated to potable water standards that are specified in Federal and State regulations and which are typically administered and enforced by a State or local agency. Following treatment, the water is either pumped directly into the distribution system or pumped into storage reservoirs from which it is subsequently pumped into the distribution system. This system of wells, pumps, storage vessels and distribution infrastructure is owned and maintained by the private utility.

The fees or rates charged for water are comprised of a fixed charge component plus a variable fee based on the volume of water used. Additional fees are typically chargeable for other services such as establishing a connection, late fees and reconnects.

In respect of sewer or wastewater services, the sewage or wastewater produced by the customer flows through a buried service lateral line, which the line is owned and maintained by the customer, from the house or commercial space to the street. This line feeds into collection pipes or lines (collection mains) located under or adjacent to the street which pipes are owned and maintained by the private utility. These pipes generally slope at a grade of approximately 0.25% as gravity is generally relied on to facilitate flows. On long line runs where maintaining slopes would result in excessive depths below grade or to traverse variable terrain, the line may terminate at a lift station where wastewater is collected and then pumped up to feed into another line located closer to the surface level where the wastewater can continue to flow by gravity. This is typically referred to as a "force main".

The wastewater is ultimately delivered to a treatment plant. Primary treatment at the plant consists of the screening out of larger solids, floating material and other foreign objects and, at some facilities, grit removal. These removed materials are hauled to a landfill. Secondary treatment at the plant consists of biological digestion of the organic and other impurities which is performed by beneficial bacteria in an oxygen enriched environment. Excess and spent bacteria are collected from the bottom of the tanks digested and or dewatered and the resulting solids sent to landfill or to land application as a soil amendment. The treated water, referred to as "effluent", is then used for irrigation or groundwater recharging or is discharged by permit into adjacent surface waters. The standards to which this wastewater is treated are specified in each treatment facility's operating permit and the wastewater is routinely tested to ensure its continuing compliance therewith. The effluent quality standards are based on Federal and State regulations which are administered and continuing compliance therewith enforced by the State agency to which Federal enforcement powers are delegated.

### (ii) Principal Markets and Regulatory Environments

The Corporation's water and wastewater facilities are located in the United States of America in the states of Arizona, Texas, Illinois, Missouri, Arkansas, and with the recent acquisition of Park Water, in the states of California and Montana. The water and wastewater utilities are generally subject to regulation by the public utility commissions of the States in which they operate. The respective public utility commissions have jurisdiction with respect to rate, service, accounting procedures, issuance of securities, acquisitions and other matters. These utilities generally operate under cost-of-service regulation as administered by these state authorities. The utilities generally use a historic test year in the establishment of rates for the utility and pursuant to this method the determination of the rate of return on approved rate base, recovery of depreciation on plant, together with all reasonable and prudent operating costs, establishes the revenue requirement upon which each utility's customer rates are determined.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on each of its water and wastewater utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved rate of return on its investments. A summary of the rates and tariffs for the wastewater treatment and water distribution business unit is attached in Schedule C.

(1) Arizona

**ACC** is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Arizona. The Arizona Department of Environmental Quality ("**ADEQ**") and the Arizona Department of Water Resources in conjunction with various County agencies (county health units) have primary jurisdiction respecting environmental regulation and compliance.

(2) Texas

**PUC Texas** is the primary regulatory agency with jurisdiction over water and wastewater treatment utilities in Texas. This regulatory responsibility was transferred from the Texas Commission on Environmental Quality (the "**TCEQ**") to PUC Texas on September 1, 2014. The TCEQ has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water and wastewater treatment service providers, including those owned and operated by municipalities.

(3) Arkansas

**PSC** is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Arkansas for rates and charges. The Arkansas Department of Health has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Clean Water Act and the Safe Drinking Water Act, for all water treatment service providers, including those owned and operated by municipalities. The Arkansas Department of Environmental Quality is the primary regulator for all discharge permits including wastewater treatment utilities in Arkansas.

(4) California

**CPUC** is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in California for rates and charges. The Division of Drinking Water of the California State Water Resources Control Board ("**SWRCB**") has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the California Safe Drinking Water Act and Title 17 and 22 of the California Code of Regulations (California has primacy) for all water service providers, including those owned and operated by municipalities., that jurisdiction of drinking water for CPUC-regulated water providers is shared between the CPUC and SWRCB pursuant to a Memorandum of Understanding. The SWRCB is the primary regulator for all discharge permits from drinking water systems in California.

(5) Montana

**MNPSC** is the primary regulatory agency with jurisdiction over the private and investor owned water utilities in Montana for rates and charges. The Montana Department of Environmental Quality has regulatory jurisdiction respecting environmental compliance, including implementing and enforcing the standards mandated by the federal Safe Drinking Water Act, for all water service providers, including those owned and operated by municipalities. The Montana Department of Environmental Quality is the primary regulator for all discharge permits in Montana.

### (iii) Material Facilities

(1) Gold Canyon water System

The Gold Canyon waste water system (the "**Gold Canyon WaterSystem**") is a wastewater treatment facility established in 1984 to serve a number of residential developments and an unincorporated area of Pinal County referred to as Gold Canyon, approximately 25 miles east of downtown Phoenix, Arizona.

The Gold Canyon Water System currently serves over 7,500 residential and commercial connections. The treatment plant utilizes a biological nutrient removal process combined with a sequencing batch reactor with a treatment capacity of 1.9 million gallons per day ("**gpd**").

The Gold Canyon Water System is a consumptive re-use facility and sells its reclaimed A+ effluent for use as irrigation water on two neighboring golf courses. Excess reclaimed water is recharged (put back into the ground to replenish underground water) via three recharge ponds. The treatment facility operates under ADEQ – Aquifer Protection Permits and Reuse Permits.

(2) LPSCo Water & Wastewater Systems

The LPSCo System located in the city of Goodyear, 15 miles west of Phoenix, Arizona whose service area includes the City of Litchfield Park and sections of the cities of Goodyear and Avondale as well as portions of unincorporated Maricopa County.

*Connection Base*

The LPSCo System presently serves approximately 18,700 water and 19,800 wastewater connections. The wastewater system has permitted capacity of 54.1 million gpd. The water infrastructure system includes a total of twelve active wells, a 6.3 million gallon reservoir and a 4.0 million gallon reservoir which provides water to the current connection base through a single pressure zone. The LPSCo System now operates at approximately 95% of design capacity and will start construction in April 2016 to expand the treatment capacity from 4.2 million gallons per day to 5.8 million gallons per day. Construction will finish in 2017. Design and permitting is complete for this project.

The LPSCo System supplies Class "A+" effluent to a number of local golf courses in the area. The LPSCO System's largest 10 connections represent approximately 8.0% of its total annual sales of approximately U.S. $24.0 million. Its largest customers are the City of Goodyear and an elementary school.

*Rate Case*

On February 28, 2013, LPSCo System filed a general rate case with the ACC seeking, among other things, an increase in EBITDA by U.S. $3.0 million over the 2012 results if approved as filed. The application sought recognition of increased capital investment and increased operating expenses over current rates. In addition to a revenue increase, the application sought for an accelerated infrastructure recovery surcharge, a purchased power pass-through mechanism to recover power price increases between test years, a property tax accounting deferral to defer increases in property taxes between test years and a policy statement on rate design to begin the gradual shift of moving more revenue recovery to fixed charges versus commodity charges. In April 2014 the ACC approved a $1.8 million increase in rates effective on May 1, 2014.

*Financing*

On October 1, 2015, the U.S. $9,800 LPSCo System IDA bonds were fully repaid.

(3) Rio Rico Water & Wastewater Systems

The Rio Rico water & wastewater systems (the "**Rio Rico System**") is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona.

*Connection Base*

The Rio Rico System serves approximately 6,900 water and 2,400 wastewater connections in the community of Rio Rico, Arizona. The Rio Rico System has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the ACC.

*Rate Case*

On October 28, 2015, the Rio Rico System filed a rate case and financing application. The application seeks a combined increase in revenue requirement of U.S. $0.9 million, based on a test year ending December 31, 2014, a combined rate base of U.S. $14.2 million, 10.8% ROE, and 70% equity, for an overall rate of return of 8.6%. The proposed revenue increases are U.S. $0.7 million, or 22.6%, for the water division and U.S. $0.2 million, or 15.3%, for the wastewater division. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the fair value Arizona rate evaluation model ("FARE"), a purchased power adjuster mechanism ("PPAM") and a property tax adjuster mechanism ("PTAM"). The FARE allows for a periodic update of all components in the revenue requirement (subject to an earnings band). A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending February 2012.

(4) Black Mountain Sewer System

The Black Mountain sewer system (the "**Black Mountain System**") is a wastewater facility located in Carefree, Arizona.

*Connection Base*

The Black Mountain System serves approximately 2,500 wastewater connections in the community of Carefree, Arizona.

*Rate Case*

On June 22, 2015, the Black Mountain System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $0.4 million, or 18.75%, based on a test year ending December 31, 2014. This rate case is primarily designed to resolve issues related to rate design and closure of the treatment plant. No amounts have been removed from rate base in this application. The increase reflects a requested return on equity of 10.8% and a debt/equity structure of 30%/70%. An all-party settlement has been achieved and was filed on January 22, 2016. The settlement includes a revenue increase of $0.2 million, premised upon a 9.5% return on equity on 70% of capital. A final decision and implementation of new rates was expected for the third quarter of 2016 but may occur sooner.

(5) Bella Vista Water System

The Bella Vista water system (the "**Bella Vista System**") is a regulated water utility in Sierra Vista, Arizona.

*Connection Base*

The Bella Vista System serves approximately 9,800 water connections in the community of Sierra Vista, Arizona.

*Rate Case*

On October 28, 2015, the Bella Vista System filed a rate case and financing application. The application seeks an increase in revenue requirement of U.S. $1.6 million, or 33.6%, based on a test year ending December 31, 2014, a rate base of U.S. $13.2 million, 11.6% ROE, and 70% equity, for an overall rate of return of 9.16%. This rate case is primarily needed to recover increased operating costs and capital improvements. It also includes approval for the FARE, a purchased power adjuster mechanism (PPAM) and a PTAM. A final decision and implementation of new rates is expected for the fourth quarter of 2016. Its previous rate case was based on a test year ending March 2009.

*Financing*

Outstanding third party indebtedness at The Bella Vista Water System consists of U.S.$0.877 million of Water Infrastructure Financing Authority of Arizona loans bearing interest rates of 6.26% and 6.10% and maturing March 1, 2020 and December 1, 2017, respectively. The loans have principal and interest payments, payable monthly and quarterly in arrears.

(6) Pine Bluff Water System

The Pine Bluff Water System is a regulated water utility located in the City of Pine Bluff, Arkansas in Jefferson County. The system is regulated by the APSC and has a franchise agreement with the City of Pine Bluff, Arkansas.

*Connection Base*

The Pine Bluff Water System serves a population of over 47,000 people comprising approximately 18,000 connections. During the year ended December 31, 2015, the Pine Bluff Water System's largest 10 connections represent approximately 25% of its total annual sales of approximately US$9.5 million Its largest customers are a food processing company, public works facilities and a university.

*Rate Case*

On July 2, 2014, Pine Bluff Water System filed an application with the Arkansas Public Service Commission ("APSC") seeking an increase in revenue of U.S. $2.5 million based on a test year ending January 31, 2014, with pro forma changes to certain operating expenses and rate base capital additions. The previous test year ended September 30, 2009. The case has concluded and an Order was issued on March 12, 2015, approving a U.S. $1.1 million revenue increase effective March 15, 2015.

(7) Park Water System

On January 08, 2016, the Distribution Group closed a previously announced agreement with Western Water Holdings, a wholly-owned investment of Carlyle Infrastructure, to acquire the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("Park Water"). Park Water owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates the water system in central Los Angeles. Apple Valley Ranchos Water Company, now known as

Liberty Utilities (Apple Valley Ranchos Water) Corp. ("Apple Valley"), owns and operates the water system in Apple Valley, California. Mountain Water Company ("Mountain Water") owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water. The three utilities collectively serve approximately 74,000 customer connections and have more than 1,000 miles of distribution mains.

The water utility in Western Montana serving the municipality of Missoula is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude, or whether the city of Missoula will ultimately take possession of Mountain Water. On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. Please see "*4.2.2 Operational Risk - Regulatory Risk - Condemnation Expropriation Proceedings*" and "*9.2 Regulatory Actions*" for a detailed description and discussion of the condemnation proceedings.

## Electric Distribution Systems

### (i) Method of Providing Services and Distribution Methods

Electric distribution is the final stage in the delivery system of providing electricity to end users. An electric distribution system's network carries electricity from the transmission system and delivers it to consumers or other end users. Typically, the network includes medium-voltage (less than 50 kV) power lines, electrical substations, various line apparatus (reclosers, fuses, lightning arrestors), and distribution transformers (pole mounted or pad-mounted), low-voltage (less than 1 kV) secondary distribution wiring and then electric meters used for billing.

An electric distribution utility sources and distributes electricity to its customers through a network of buried or overhead lines. The electricity is sourced from power generation facilities which can use various fuels such as water (hydro), natural gas, coal, bio-mass, wind, nuclear and solar. The electricity is transported from the source(s) of generation at high voltages through transmission lines and is then reduced through transformers to lower voltages at substations. The electricity from the substations is then delivered through distribution lines to the customers where the voltage is again lowered through a transformer for use by the customer.

The rates charged for electric distribution service are comprised of a fixed charge that recovers customer related costs, such as meter readings, and a variable rate component that recovers the cost of generation, transmission and distribution. Other revenues are comprised of fees for other services such as establishing a connection, late fee, reconnections, and energy efficiency programs, for example.

The electrical distribution utilities located in California and New Hampshire are subject to state regulation and rates charged by these utilities must be reviewed and approved by their respective State regulatory authorities.

### (ii) Principal Markets and Regulatory Environments

The Corporation operates electrical distribution systems in the states of California and New Hampshire under a cost-of-service methodology. The utilities use an historical test year, pro-formed for known and measurable changes, in the establishment of their rates. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses and administrative and general expenses.

Rate cases ensure that a particular utility recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the utility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. In the case of the CalPeco Electric System a rate case filing is mandatory every 3 years. A summary of the rates and tariffs for the Distribution Group's electric distribution utilities is attached in Schedule D.

(1) California

The CPUC regulates investor owned utilities in California and approves the rate of return and the rate base which affects the profitability of the utility.

Energy Cost Adjustment Clause ("**ECAC**") is an annual filing that sets rates to recover the next year's fuel and purchased power costs in addition to setting rates to recover or refund any under/over recovery of previous year's fuel and purchased power costs.

Post Test Year Adjustment Mechanism ("**PTAM**") allows the CalPeco Electric System to update its rates annually by a cost inflation index. In addition, rates are updated to recover the return on investment and associated depreciation of major capital projects that are placed in service and meet a certain cost threshold.

The Base Revenue Requirement Balancing Account ("**BRRBA**") removes the seasonal variations of the revenues and flattens the net revenue (minus fuel, purchased power, and ECAC) to a monthly rate of $3.0 million or $36.0 million annually. This eliminates the risk of revenue variations associated with seasonal weather changes.

(2) New Hampshire

The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety. New Hampshire introduced "retail choice" for customers in 1998. Utility companies are allowed to file distribution rate cases from time to time as the companies determine a need to request adjustments to base rates. There are a number of adjustment factors also in rates, for reliability enhancement programs, vegetation management, energy efficiency and low income programs, all of which are reconciled on an annual basis. Electricity distribution companies are also required to provide electricity commodity service for its customers who do not elect to take service from a competitive supplier. Costs for commodity service are recovered on a direct pass through basis.

## (iii) Material Facilities

(1) CalPeco Electric System

The CalPeco Electric System provides electric distribution service to the Lake Tahoe basin and surrounding areas. The service territory, centered on a highly popular tourist destination, has a customer base spread throughout Alpine, El Dorado, Mono, Nevada, Placer, Plumas and Sierra Counties in northeastern California. The distribution system is comprised of approximately 94 miles of high voltage distribution lines, 13 substations, and 39 distribution circuits (14.4 kV) serving approximately 48,500 connections.

*Connection Base*

CalPeco Electric System's connection base of approximately 48,500 connections is primarily residential with large commercial accounts limited to less than 20% of gross revenues. The commercial connections consist primarily of ski resorts, hotels, hospitals, schools and grocery stores. The CalPeco Electric System's largest 10 connections represent approximately 12.6% of its total annual sales of approximately U.S. $74.1 million. Its largest customers are major ski resorts and large region school district.

*Rate Case*

The CalPeco Electric System's most recent approved rate case was filed and settled in 2012. The CPUC's decision adopted an all-party settlement for the test year of 2013. The settlement included a combined increase in both Base Rates and the ECAC of $3.7 million in 2013; a test year rate base of $121.2 million; a 2013 return on equity of 9.9%, based upon a capital structure of 48.5% debt and 51.5% equity, using a long-term debt cost of 5.5% and resulting in an overall rate of return of 7.8%. Rates were implemented on January 1, 2013.

Another element of the decision, a revenue decoupling mechanism and a vegetation management memorandum account was agreed upon. The revenue decoupling mechanism will decouple base revenues from fluctuations caused by weather and economic factors. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility.

A pending general rate case application for the CalPeco Electric System was filed in Q2 2015. It is based on a historical test year of calendar 2014, with pro-forma adjustments for known and measurable changes in calendar 2015 and 2016. It proposes an increase in revenue of U.S. $13.6 million, or 17.3%, rate base of $150.9 million, 10.5% ROE and 55% equity. New rates are expected to be effective in the second quarter of 2016 with new rates retroactive to January 2016.

*Kings Beach Generation*

The CalPeco Electric System has a local-area emergency backup generation facility at Kings Beach (the "**King Beach Facility**") in Placer County, California. The facility consists of six new Caterpillar 3516 Engine diesel generation units with a total nameplate capacity of 12 MW. The units were installed in November 2008 at a cost of U.S. $16.5 million and have an estimated useful life of 30 years. The repowered facility meets all California environmental standards.

In the event of a system outage, the Kings Beach Facility is able to provide limited back-up generation support to the CalPeco Electric System's service territory until baseload power is restored. The facility includes quick-start technology which facilitates this support function. The new units are designed to be online and operating within 1 minute of being activated. The Kings Beach Facility has historically run an average of 200 hours per year.

*Energy Cost Adjustment Clause*

ECAC is an annual filing that sets "base rates" to recover the next year's fuel and purchased power costs in addition to setting "amortization rates" to recover or refund any under/over recovery of previous year's fuel and purchased power costs. Rates are effective January 1st of every year.

*Post Test Year Adjustment Mechanism*

In years where the CalPeco Electric System does not file a general rate case, its rates are updated on January 1st to reflect inflationary increases to its administrative, operations, and maintenance costs. The inflationary adjustment is set by the use of an index, less a presumed efficiency offset.

The CalPeco Electric System may also file for an annual increase in rates to recover its investment costs in material capital projects. This increase is subject to a materiality threshold.

*Base Revenue Requirement Balancing Account*

BRRBA is used to record the difference between the CalPeco Electric System's CPUC authorized annual base rate revenue requirements and the annual recorded revenue from base rates. The disposition of the balance in the BRRBA is addressed by an annual filing.

*PPA*

The CalPeco Electric System entered into a five year all-purpose PPA with NV Energy Inc. ("NV Energy") to provide its full electric requirements at rates NV Energy's "system average cost" that became effective on January 1, 2011, with a five year renewal option. During 2015, the Corporation entered into a new multi-year Services Agreement with NV Energy commencing January 2016. The PPA obligates NV Energy to use commercially reasonable efforts to supply the CalPeco Electric System with sufficient renewable power to, combined with the solar project described below, satisfy the current California Renewables Portfolio Standard requirement for the five-year term of the PPA.

The CalPeco Electric System filed an Application with the CPUC in Q2 2015 for authorization to enter into a multi-year Services Agreement with NV Energy commencing January 2016 and authority to recover the costs it will incur under the 2016 NV ESA as energy purchase costs. CPUC approval was received in the fourth quarter of 2015 for the new PPA.

*Solar Project*

The CalPeco Electric System filed an Application with the CPUC in Q2 2015 for the issuance of a CPCN to acquire, own and operate two solar projects, the 40 MW Luning Solar Energy Center ("Luning Project") and the 20 MW Minden Sunrise Solar Project ("Minden Project") (collectively, the "Solar Projects") and authorize rate recovery for the costs that the CalPeco Electric System will incur to acquire, own, and operate the Solar Projects. A settlement was achieved and the CPUC approved a modified Luning Project, at 50 MW, in the first quarter of 2016.

*Financing*

The CalPeco Electric System entered into a long term debt private placement in an amount of U.S. $70.0 million on December 29, 2010. The private placement is a senior unsecured private placement with U.S. institutional investors. The notes are fixed rate, interest only, and split into two tranches, U.S. $45.0 million of ten year 5.19% notes and U.S. $25.0 million of 5.59% fifteen year notes.

(2) Granite State Electric System

The Granite State Electric System provides distribution service to approximately 44,800 connections in 21 communities located in two franchise service areas in southern and northwestern New Hampshire, centered around operating centers in Salem in the south and Lebanon in the northwest. Across approximately 810 square miles of service area, the Granite State Electric System's assets consist of 908 miles of overhead distribution lines, 231 miles of underground distribution lines, 15 distribution substations, 37 distribution circuits and 9 sub-transmission circuits.

*Connection Base*

The Granite State Electric System's customer base consists of a mixture of residential, commercial and industrial customers. The system's residential customer base represents approximately 38,300 connections, while the commercial and industrial customer base represents approximately 6,500 connections. The commercial and industrial connections are a mix of commercial, retail, medical, education and manufacturing with its largest 10 connections representing approximately 12.1% of its total annual sales of approximately U.S. $101.5 million. Its largest customers are a world renowned medical facility and an Ivy League educational institution.

*Rate Case*

In the first quarter of 2013, the Granite State Electric System filed a rate case with the NHPUC which sought an increase in rates of U.S. $13.0 million, and an additional U.S. $1.2 million increase in 2014 subject to the completion of certain capital projects. On March 17, 2014, the commission approved a settlement of U.S. $9.8 million and U.S. $1.1 million step increase for 2014. The rates came into effect April 1, 2014.

*Default Service Adjustment Provision*

Granite State Electric System is required to provide electric commodity supply (Default Service) for all customers who do not choose to take supply from a competitive supplier in the New England power market. The competitive market is overseen by the ISO-NE. As an electric distribution utility, Granite State Electric System is required to participate in the ISO-NE market and abide by its rules under FERC. The Granite State Electric System is allowed to fully recover its costs for the provision and administration of Default Service under the Default Service Adjustment Provision, as approved by the NHPUC. The Granite State Electric System must file with the NHPUC twice a year to adjust for market prices of power purchased.

*Financing*

Outstanding third party indebtedness at the Granite State Electric System consists of unsecured notes issued in three tranches for an aggregate amount of U.S. $15.0 million: U.S. $5.0 million bearing an interest rate of 7.37%, maturing November 1, 2023; U.S. $5.0 million bearing an interest rate of 7.94%, maturing July 1, 2025; and U.S. $5.0 million bearing an interest rate of 7.30%, maturing June 15, 2028. The notes are interest only and payable semi-annually.

### Natural Gas Distribution Systems

### (i) Method of Providing Services and Distribution Methods

Natural gas is a fossil fuel composed almost entirely of methane (a hydrocarbon gas) usually found in deep underground reservoirs formed by porous rock. In making its journey from the wellhead to the customer, natural gas may travel thousands of miles through interstate pipelines owned and operated by pipeline companies.

Because gas flowing from higher to lower pressure is the fundamental principle of the natural gas delivery system, compressor stations may be located every 50-60 miles along the pipelines to boost pressure that is lost through friction. Also along the route, the natural gas may be stored underground in depleted oil and gas wells or other natural geological formations for use during seasonal periods of high demand.

Interstate pipelines interconnect with other pipelines and other utility systems, and offer system operators flexibility in moving the gas from point to point. The interstate pipeline companies are regulated by the FERC. The gas is transported from various sources at high pressures through transmission lines and is then reduced through gate stations to distribution pressures.

The gas from the gate stations is then delivered through distribution lines to the customer where the gas pressure is again lowered through district regulator stations and/or meter regulators for use by the customer. Typically, the distribution network operates pipelines, gate stations, district regulator stations, peak shaving plants and natural gas meters.

The gas distribution utilities owned by the Corporation are subject to state regulation and rates charged by these facilities may be reviewed and altered by the State regulatory authorities from time to time.

### (ii) Principal Markets & Regulatory Environments

The Corporation owns and operates natural gas distribution systems, under cost-of-service regulation in the states of Illinois, Iowa, Missouri, Georgia, Massachusetts and New Hampshire. The natural gas utilities use a test year to determine distribution rates for the utility. Pursuant to this method, the revenue requirement upon which rates are based is determined by applying an approved return on rate base, and adding depreciation, operating expenses, and administrative and general expenses.

Rate cases ensure that a particular facility appropriately recovers its operating costs and has the opportunity to earn a reasonable rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The Corporation monitors the rates of return on its utility investments to determine the appropriate times to file rate cases in order to ensure it earns a reasonable rate of return on its investments. A summary of the rates and tariffs for the Corporation's Distribution Group' natural gas distribution utilities is attached in Schedule E.

(1) New Hampshire

In New Hampshire, gas utilities are regulated by the NHPUC. The NHPUC is vested with general jurisdiction over electric, telecommunications, natural gas, water and sewer utilities as defined in applicable legislation for issues such as rates, quality of service, finance, accounting, and safety.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(2) Illinois

The Corporation's Illinois operations are regulated by the Illinois Commerce Commission ("**ICC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA ("PGA").

(3) Iowa

The Corporation's Iowa operations are regulated by the Iowa Utilities Board ("**IUB**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(4) Missouri

The Corporation's Missouri operations are regulated by the Missouri Public Service Commission ("**MPSC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(5) Georgia

The Corporation's Georgia operations are regulated by the Georgia Public Service Commission ("**GPSC**").

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

(6) Massachusetts

The Corporation's Massachusetts operations are regulated by the Commonwealth of Massachusetts. The Massachusetts Department of Public Utilities ("**MDPU**") has regulatory jurisdiction over all public utilities and common carriers operating in the commonwealth, which jurisdiction includes the establishment of approved tariffed rates for the purpose of billing customers.

The rates and fees for providing gas service to end users and recovering the authorized rate of return are in the form of a fixed monthly charge and a volumetric distribution charge. The rates billed to recover gas costs are in the form of the tariffed PGA.

### (iii) Material Facilities

(1) EnergyNorth Gas System

The EnergyNorth Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 89,900 connections in 30 communities covering five counties in New Hampshire. Its franchise service area includes the communities of Nashua, Manchester and Concord, New Hampshire. The EnergyNorth Gas System is the largest natural gas distribution utility in the State, with a distribution system consisting of 2,140 miles of distribution pipelines, 2.8 miles of transmission pressure gas pipelines and eight city gate stations, or distribution supply points.

*Customer Base*

The EnergyNorth Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 80,300 connections, while the commercial and industrial customer base represents approximately 9,600 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The EnergyNorth Gas System's largest 10 connections represent approximately 2.5% of its total annual sales of approximately U.S. $143.8 million. Its largest customers are a technology company and multiple public works facilities.

*Rate Case*

On August 1, 2014, the EnergyNorth Gas System in New Hampshire filed an application for a total increase in revenue of U.S. $16.1 million, or approximately 9.6%. This proposed increase consists of U.S. $13.4 million of permanent base distribution rates and a step increase of U.S. $2.7 million for investments made during a pro forma period. The application includes a revenue decoupling proposal and seeks recovery of capital costs related to the conversion of the system to the Corporation's ownership. A temporary rate increase was approved on November 21, 2014 allowing a U.S. $7.4 million interim rate increase effective December 1, 2014, retroactive to November 2014 upon approval of permanent rates. On June 26, 2015, an Order was issued approving a settlement agreement allowing for a U.S. $12.4 million revenue increase effective July 1, 2015.

*Energy Cost Adjustment Clause*

The cost of gas ("COG") delivered to customers is recovered when billed to "firm" gas customers through the operation of gas adjustment clauses included in utility tariffs. The COG provision requires periodic reconciliation of recoverable gas costs and COG revenues.

*Growth Projects*

The EnergyNorth System in New Hampshire recently filed three applications with the New Hampshire Public Utilities Commission to obtain the franchise rights to provide gas to new territories. One was filed in July 2015 seeking approval to obtain the franchise rights to the Town of Hanover and City of Lebanon. This docket is expected to conclude in the second quarter of 2016. A second was filed in August 2015 seeking the franchise rights to the towns of Pelham and Windham. This docket is expected to conclude in the second quarter of 2016. A third application was filed in October 2015 to serve the towns of Jaffrey, Rindge, Swanzey, and Winchester. This docket is expected to conclude in the second quarter of 2016.

(2) Midstates Gas System

The Midstates Gas System owns regulated natural gas utilities providing natural gas distribution services to approximately 84,200 connections in 190 communities in the states of Illinois, Iowa and Missouri. The franchise service area includes the communities of Virden, Vandalia, Harrisburg and Metropolis in Illinois, Keokuk in Iowa, and Butler, Kirksville, Canton, Hannibal, Jackson, Sikeston, Malden and Caruthersville in Missouri. The Midstates Gas System has a distribution system consisting of 2,795 miles of distribution pipelines, 243 miles of transmission pressure gas pipelines and 102 city gate stations, or town border supply points.

*Customer Base*

The Midstates Gas System serves approximately 22,900 connections in Illinois, 4,400 connections in Iowa and 56,700 connections in Missouri with a mix of residential, commercial, industrial and transportation customers. Of the 84,000 connections, approximately 74,300 (88%) are residential connections, while 9,700 (12%) are commercial and industrial connections. The commercial and industrial connection base is a diversified mix of retail, medical, education and industrial uses. The Midstates Gas System's largest 10 connections represent approximately 5.3% of its total annual sales of approximately U.S. $74.9 million. Its largest customers are a biotechnology Corporation and a manufacturing Corporation.

*Energy Cost Adjustment Clause*

Illinois allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the calendar year. An annual reconciliation is filed based on the 12 months ended December.

Iowa allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted monthly with an annual reconciliation based on the 12 months ended August of each year.

Missouri allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, and storage costs). The rate is adjusted annually (in fourth quarter) with allowance to file quarterly. An annual reconciliation is filed based on the 12 months ended August of each year.

*Rate Case*

On March 31, 2014, the Midstates Gas System filed a rate case with the ICC seeking an increase in revenue of U.S. $5.7 million. The filing was based on a test year that includes anticipated capital expenditures within 2014 and 2015. The case has concluded and an Order was issued on February 11, 2015, approving a U.S. $4.6 million revenue increase effective February 20, 2015.

(3) Peach State Gas System

The Peach State Gas System is a regulated natural gas system providing natural gas distribution services to approximately 64,300 connections in 13 communities covering six counties in Georgia. Its franchise service area includes the communities of Columbus, Gainesville, Waverly Hall, Oakwood, and Hamilton, GA. The regulated Peach State Gas System has a distribution system consisting of approximately 1,200 miles of distribution pipelines, approximately 70 miles of transmission pressure gas pipelines and four city gate stations, or distribution supply points.

*Customer Base*

The Peach State Gas System's customer base consists of a mixture of residential, commercial, industrial and transportation customers. The system's residential customer base represents approximately 60,000 connections, while the commercial and industrial customer base represents approximately 4,300 connections. The commercial and industrial customer base is a diversified mix of retail, medical, educational and industrial uses. No one connection represents more than 3% of its connection base. The utility also maintains and operates the distribution system for a large US Army military base, consisting of approximately 116 miles of distribution pipelines, through a special privatization contract. The Peach State Gas System's largest 10 connections represent approximately 7.3% of its total annual sales of approximately U.S. $63.7 million. Its largest customers are poultry and textile producers.

*Rate Case*

The Peach State Gas System's rates are reviewed and updated annually through a tariff provision called the Georgia Rate Adjustment Mechanism ("**GRAM**"). This mechanism allows for the annual review of cost recoveries and the setting of rate base returns with a target of 10.7% return on equity and a range of 10.5% to 10.9%. The mechanism includes a provision to "true up" revenues in the subsequent year to capture or refund under or over collections. The annual GRAM filing is due October 1st of each year and the rates approved through the filing go into effect February 1st of the following year. The mechanism includes a forward looking view of cost of service based on approved inflation factors and also includes certain forecasted capital expenditures.

On October 1, 2015, the Peach State Gas System filed an application for an increase in revenue of U.S. $3.4 million in its annual GRAM filing with the Georgia Public Service Commission. New rates were to be effective February 1, 2016, for the period February 1, 2016, through January 31, 2017 to reflect changes in revenue levels and cost of service. The GRAM uses a 12 month base period ending June 2015 (historic test year), with adjustments for the 12 months ending September 2016 (forward looking test year). Commission approval was received in February 2016, allowing for a U.S. $2.7 million rate increase effective March 1, 2016. The difference from the original proposed amount was due to tax depreciation rates and the use of revised inflationary factors applied to operating expenses.

The Peach State Gas System also files an annual Pipe Replacement Program revision to adjust the rates collected for capital costs incurred to replace cast iron and bare steel pipe in its system. The filing is made each February 15th and the rate adjustment, calculated using a 10.7% ROE, takes effect on October 1st of the same year. The program is due to be completed in 2016, and the associated rate base under this program will be rolled into the annual GRAM filing in 2018.

*Energy Cost Adjustment Clause*

Georgia allows full recovery of all gas costs (including commodity price, transportation, reservation and demand costs, hedging costs, storage costs). The cost of gas delivered to customers is recovered when billed to "sales" gas customers through the operation of PGA clauses included in utility tariffs. The PGA requires a change in rates at least every three months. Each year the utility files a gas supply plan on July 1st with an effective date of October 1st.

(4) New England Gas System

The New England Gas System is a regulated natural gas utility providing natural gas distribution services to approximately 54,200 customers in six communities located in the southeastern portion of Massachusetts. The New England Gas System's distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas Systems receives gas at five delivery points or gate stations along the Algonquin Gas Transmission Corporation (Spectra Energy) transmission system.

*Customer Base*

The New England Gas System's customer base consists of a mixture of residential, commercial, and industrial customers. The system's residential customer base represents approximately 50,600 connections, while the commercial and industrial customer base represents approximately 3,700 connections. New England Gas System's distribution network consists of 609 miles of distribution main and 35,660 service lines. The New England Gas System's largest 10 connections represent approximately 4.6% of its total annual sales of approximately U.S. $54.2 million. Its largest customers are waste management and textile companies.

*Rate Case*

On July 16, 2015, the New England Gas System filed an application with the MDPU seeking an increase in revenue of U.S. $11.8 million, or 14.6%, based on a test year ending December 31, 2014, adjusted for known and measurable changes in calendar 2015. This application represents the first rate case under the Distribution Group's ownership. It seeks an increase in its general rates for increasing capital costs associated with maintaining the infrastructure and increases in operating and maintenance expenses. The increase reflects a requested return on equity of 10.4% and a debt/equity structure of 45%/55%. An all-party settlement was achieved and filed in December 2015. The settlement includes a two-step revenue increase totaling $8.3 million, premised upon a 9.6% return on equity on 50% of capital. A $7.8 million revenue increase will be effective March 1, 2016, and a further $0.5 million revenue increase will be effective March 1, 2017, contingent upon specified employee additions. On February 10, 2016, an Order was issued approving the settlement agreement.

New England Gas System's prior rate case was filed with the MDPU on September 16, 2010 and docketed as MDPU-10-114. On March 31, 2011, the MDPU issued its order awarding the New England Gas System an increase in base distribution revenues of $5.1 million. In addition the MDPU granted approval of a targeted infrastructure replacement factor to facilitate recovery of costs associated with its aging infrastructure replacement program, and a revenue decoupling mechanism proposed by the New England Gas System to mitigate the effects of lost revenue associated with energy efficiency and to stabilize earnings variability associated with weather.

*Energy Cost of Gas Adjustment Clause*

The cost of gas is fully recoverable from customers through the Gas Adjustment Factor ("**GAF**") when billed to "firm" gas customers included in approved tariffs by the MDPU. The GAF is adjusted (May and November) and more frequently if the monthly gas cost forecast differs from the originally forecasted by >5%.

*Financing*

The New England Gas System currently has outstanding indebtedness in the form of first mortgage bonds consisting of three tranches for an aggregate amount of U.S. $19.5 million: U.S. $6.5, bearing an interest rate of 9.44%, maturing February 15, 2020; U.S. $7.0, bearing an interest rate of 7.99%, maturing September 15, 2026; U.S. $6.0, bearing an interest rate of 7.24%, maturing December 15, 2027. The notes have interest only payments, payable semi-annually in arrears.

### 3.2.3 Specialized Skill and Knowledge

The Distribution Group requires specialized knowledge of the utility systems served including electrical, gas or water and waste water distribution. Upon acquiring a new utility system the Distribution Group will typically retain the existing employees with such specialized skill and knowledge.

In addition, the Distribution Group will add, when required, additional utility trained personnel at its corporate offices to support the expanded portfolio of utility assets.

### 3.2.4 Competitive Conditions

The Distribution Group's businesses have geographic monopolies in their service territories and are therefore insulated from competition. The Distribution Group has developed significant in-house regulatory expertise in order to effectively interact with the state regulators in the various jurisdictions in which it operates. The Distribution Group believes that the relationship with regulators is unique to each state and therefore is best delivered by local managers who work in the service territory. The local regulatory teams meet with regulatory agencies on regular basis to review regulatory policies, service delivery strategies, operating results and rate making initiatives.

### 3.2.5 Cycles & Seasonality

#### (i) Water & Wastewater Systems

Demand for water is affected by weather conditions and temperature. Demand for water during warmer months is generally greater than cooler months due to requirements for irrigation, swimming pools, cooling systems and other outside water use. If there is above normal rainfall or rainfall is more frequent than normal the demand for water may decrease adversely affecting revenues.

Water distribution facilities depend on an adequate supply of water to meet present and future demands of customers. Drought conditions could interfere with sources of water supply used by the utilities and affect their ability to supply water in sufficient quantities to existing and future customers. An interruption in the water supply could have an adverse effect on the results of operations of the utilities. Government restrictions on water usage during drought conditions could also result in decreased demand for water, even if supplies are adequate, which could adversely affect revenues and earnings.

#### (ii) Electricity Systems

The CalPeco Electric System's demand for energy sales are primarily affected by weather conditions. Above normal snowfall in the Lake Tahoe area brings more tourists with an increased demand for electricity by small commercial customers. Prior to January 1, 2013, CalPeco Electric System was exposed to volume sales risk related to seasonal weather variations. Effective on January 1, 2013, pursuant to the CPUC General Rate Case decision, a BRRBA rate mechanism has been implemented. The BRRBA removes the seasonal variations of revenues and flattens the net revenue (gross revenues less fuel, purchased power, and the ECAC deferral) to a monthly amount of approximately U.S, $3.0 million or U.S. $36.0 million annually. This mechanism eliminates the risk of revenue variations associated with seasonal weather changes.

The Granite State Electric System experiences peak loads in both the winter and summer seasons, due to heating and cooling loads associated with New England weather. The competitive market for power supply is managed by the ISO-NE. The Default Service price for power may fluctuate as a result of the weather, but those costs are passed through directly to customers.

The Granite State Electric System offers a comprehensive menu of energy efficiency programs in New Hampshire that, in turn, may reduce the demand for energy. These programs are funded via a charge in distribution rates known as the systems benefit charge, which applies to all utilities. This mechanism provides for an annual reconciliation of costs. The company has an opportunity to earn a performance incentive if it is successful in achieving its annual energy efficiency targets.

#### (iii) Natural Gas Systems

The Distribution Group's primary demand for natural gas from its natural gas distribution systems is driven by the seasonal heating requirements of its residential, commercial, and industrial customers. The colder the weather, the greater the demand for natural gas to heat homes and businesses. As such, the natural gas distribution systems demand profiles typically peaks in the winter months of January and February and declines in the summer months of July and August. Year to year variability also occurs depending on how cold the weather is in any particular year.

The Corporation attempts to mitigate the above noted risks by seeking regulatory mechanisms during rate case proceedings. Certain jurisdictions have approved constructs to mitigate demand fluctuations. For example, at the Peach State Gas System in Georgia, a weather normalization adjustment is applied to customer bills during the months of October through May that adjusts commodity rates to stabilize the revenues of the utility for changes in billing units attributable to weather patterns. Not all regulatory jurisdictions in which the Distribution Group operates have approved mechanisms to mitigate demand fluctuations.

### 3.2.6 Customers

The Distribution Group's businesses derive their revenues from a diverse residential, commercial and industrial customer base. For the twelve months ended December 31, 2015, electricity sales and distribution were approximately 52% from residential customers and 48% from commercial and industrial customers; natural gas sales and distribution were approximately 63% from residential customers and 37% from commercial and industrial customers; and water and waste water sales were approximately 73% from residential customers and 27% from commercial and industrial customers.

## 3.3 Transmission Group

### 3.3.1 Regulatory Regimes - Pipeline Transmission Systems

Interstate natural gas pipeline transmission assets are regulated primarily by the FERC under the Natural Gas Act. Under this framework, this agency authorizes and certifies all construction, and or abandonment of interstate gas pipeline facilities, requires certificate holders, once operational, to establish and maintain an OATT and publicly post capacity available for transportation, and the agency periodically reviews, under just and reasonable standards, the tariff rates to be charged by the certificate holder. In addition, the FERC prescribes operating and safety standards to be followed along with other federal agencies such as Department of Transportation and the Occupational Safety and Health Administration.

### 3.3.2 Description of Operations

### Natural Gas Pipeline Transmission

#### (i) Method of Providing Services and Distribution Methods

Pipelines offer a variety of services under their FERC tariffs to include firm and interruptible transportation, along with other services to provide commercial markets additional flexibility. Some examples of these types of services would be park and loan, pooling and balancing services. In addition, firm service tariff features would also provide additional features to support secondary market activity to include, but not limited to capacity assignment, capacity releases, segmentation and renewal options. Under the FERC environment, a shipper must have the good right or title to the gas for transportation. Under the FERC regulations, a considerable amount of daily and current information about each pipeline system capacity and related shipper and capacity information is available on their public Electronic Bulletin Boards or public websites.

#### (ii) Investments

As part of the Kinder Morgan Northeast Energy Direct Project, the Transmission Group has secured investment participation rights.

(1) Northeast Expansion Project

On November 24, 2014, APUC announced its agreement to participate in a Northeast natural gas pipeline transmission project in partnership with Morgan, Inc. ("Kinder Morgan") in connection with Kinder Morgan's Northeast Energy Direct project to serve New England natural gas markets. Specifically, Kinder Morgan Operating L.P. "A," a wholly owned subsidiary of Kinder Morgan, and Liberty Utilities (Pipeline & Transmission) Corp., a wholly owned subsidiary of APUC, agreed to form Northeast Expansion to undertake the development, construction and ownership of a 30-inch natural gas transmission pipeline to be located between Wright, New York and Dracut, Massachusetts (the "**Market Path Projec**t"), which will be operated by Tennessee Gas Pipeline Company, L.L.C. The Project is scalable up to 1.3 billion cubic feet per day (Bcf/d), and the pipeline capacity will be contracted with local gas and electric distribution utilities, and other customers, to help ease constraints on natural gas supply in the Northeast U.S. and help ensure much needed reliability to the power-generation grid. Under this framework, Tennessee Gas Pipeline Company, L.L.C would lease the newly constructed capacity from the Project and render the capacity, as Operator, under its tariff as regulated by the open access regulations of the FERC.

(2) Northeast Supply Path Project

On December 1, 2015, APUC announced a second agreement to participate in the upstream segment of the overall Kinder Morgan project forming Northeast Supply to undertake the development, construction and ownership of a 30-inch natural gas transmission pipeline to be located between Wright, New York and northeastern PA (the "**Supply Path Project**"), which will, like the Market Path Project, also be operated by Tennessee. Similar to the Market Path Project, Tennessee would lease the newly constructed capacity from the Project and render the capacity, as Operator, under its tariff as regulated by the open access regulations of the FERC. An in service date of November 2018 is targeted for the Market Path Project and the Supply Path Project.

## 3.4 Related Party Transactions and Business Associations with Senior Executives

**Emera Inc.**

A member of the Board of APUC is an executive at Emera. During 2015, the Energy Services Business sold electricity to Maine Public Service Company ("MPS"), and Bangor Hydro ("BH") subsidiaries of Emera, amounting to U.S.$6,658 (2014 - U.S. $9,821). During 2015, Liberty Utilities purchased natural gas amounting to U.S. $2,292 (2014 - U.S.$3,961) from Emera for its gas utility customers. Both the sale of electricity to Emera and the purchase of natural gas from Emera followed a public tender process the results of which were approved by the regulator in the relevant jurisdiction.

There was U.S.$491 included in accruals in 2015 (2014 - U.S.$nil) related to these transactions at the end of the years.

**Equity-method investments**

The Company provides administrative services to its equity-method investees and is reimbursed for incurred costs. To that effect, the Company charged its equity-method investees $2,021,000 (2014 - $189,000) during the year.

**Senior Executives**

As at December 31, 2015, $nil (December 31, 2014 - $47,000) was due from Algonquin Power Systems Ltd., a corporation partially owned by Ian Robertson and Chris Jarratt (collectively the "Senior Executives").

**Chartered Aircraft**

As part of its normal business practice, APUC has utilized chartered aircraft when it is beneficial to do so and had previously entered into a block time agreement to charter aircraft in which Senior Executives have a partial ownership. The Company terminated the agreement effective June 28, 2015 and paid a usage shortfall fee of $13,000. During the year ended December 31, 2015, APUC reimbursed direct costs in connection with the use of the aircraft prior to termination of the block time agreement of $507,000 (2014 - $721,000).

**Office Facilities**

Until the fourth quarter of 2014, APUC had leased its head office facilities from an entity partially owned by Senior Executives. During the fourth quarter of 2014, APUC terminated the related party lease and moved all head office employees into new premises owned by the Corporation. Base lease costs for the year ended December 31, 2015 were $nil (2014 - $356,000).

**Other**

A spouse of one of the Senior Executives was employed to provide market research services to certain subsidiaries of the Corporation. During the year ended December 31, 2015, APUC paid $22,000 (2014 - $192,000) in relation to these services. The spouse is no longer employed by the Corporation. Effective December 31, 2013, APUC acquired the shares of APCI which was partially owned by Senior Executives. A final post-closing adjustment related to the transaction is expected to be settled in 2016.

## 3.5 Principal Revenue Sources

As at March 11, 2016, APUC owned, directly or indirectly, debt, equity and royalty and other interests in forty-one renewable generation facilities and four thermal generation facilities including those identified in "Corporate Structure – Intercorporate Relationships – Other Interests in Energy Related Developments", two electrical distribution utilities, six natural gas distribution utilities, 1 propane gas distribution utility, and 23 water distribution and wastewater utilities.

For the year ended December 31, 2015, APUC derived approximately 21.7% of its revenues from its interests in power generation facilities (21.5% in 2014), 21.8% of its revenues from electrical distribution utilities (21.7% in 2014), 45.2% of its revenues from natural gas distribution utilities (47.4% in 2014), and 7.6% of its revenues from its interests in water distribution and wastewater utilities (7.1% in 2014).

The purchase of electricity and natural gas by the Corporations's electric distribution and natural gas distribution system is a significant revenue driver and component of operating expenses, but these costs are effectively passed through to its customers. As a result, the Corporation uses 'net utility sales' (see non-GAAP Financial Measures) are a more appropriate measure of the results. Adjusting for the impact of these commodity costs APUC derived approximately 29.9% of its revenues from its interests in power generation facilities (31.3% in 2014), 14.2% of its revenues from electrical distribution utilities (16.2% in 2014), 38.0% of its revenues from natural gas distribution utilities (35.5% in 2014), and 12.1% of its revenues from its interests in water distribution and wastewater utilities (12.8% in 2014).

## 3.6 Environmental Protection

APUC's businesses encompass operations which require adherence to environmental standards imposed by regulatory bodies through licenses, permits, standards, policies and legislation. Failure to operate such businesses in strict compliance with these regulatory standards may expose them to citations, claims, clean-up costs, penalties, and loss of operating licenses and permits.

APUC has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on APUC's capital expenditures, earnings and competitive position for the twelve months ended December 31, 2015. Moreover, other regimes that provide incentives and credits for generation of renewable energy and for carbon offsets are expected to increase the earnings and benefit the competitive position of APUC.

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation and utilities business segments which have the potential to become environmental liabilities *(see Enterprise Risk Management - Environmental)*. Many of these risks are mitigated through the maintenance of adequate insurance which include property, boiler and machinery, environmental and excess liability policies.

To manage these risks responsibly, APUC has ensured that environmental and compliance departments have been established within the different subsidiaries which are responsible for monitoring all of each subsidiary's operations, ensuring all operating facilities are in compliance with environmental regulations and preparing regulatory submissions as required.

## 3.7 Employees

APUC's Executive Management Group consists of eight individuals including the Presidents of the Generation Group and the Distribution Group. As at January 31, 2016, APUC employed 1,466 people (including 143 employees who joined the organization upon the acquisition in January 2016 of the water systems operated by Park Water and Mountain Water in California and Montana respectively.

The Generation Group employs a total of 155 employees. All of the employees of the Generation Group entities are non-unionized. Five employees at the Tinker Hydro Facility are no longer represented by a union as of January 28, 2016.

The Distribution Group employs a total of 1,168 employees. The Distribution Group employees are non-unionized with the exception of: 63 employees at the CalPeco Electric System, 42 employees at the Midstates Gas System, 177 employees at the EnergyNorth Gas and Granite State Electric System, and 77 employees at the New England Gas System.

The Corporate and shared services groups consist of an additional 143 employees located at the APUC corporate offices in Oakville, Ontario.

## 3.8 Foreign Operations

As at December 31, 2015, approximately 81% of EBITDA and 80% of cash flow are generated from operations located in the United States and are denominated in U.S. Dollars.

## 3.9 Economic Dependence

The largest customer on a percentage basis is PJM, which totalled 3.9% of gross revenues in the year ended December 31, 2015. PJMmaintains an Aa3 rating issued by Moody's and receivables from PJM are invoiced monthly and generally collected within 14 days.

The second largest customer on a percentage basis is Manitoba Hydro which totalled 2.9% of gross revenues in the year ended December 31, 2015. This customer maintains an Aa1 rating issued by Moody's and receivables are invoiced monthly and generally collected within 20 days.

The third largest customer is Quebec Hydro, totaling 2.7% of gross revenues in the year ended December 31, 2015. This customer maintains an Aa2 rating issued by Moody's and receivables are invoiced monthly and generally collected within 20 days.

Otherwise, APUC does not believe it is substantially dependent on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or license or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

## 3.10 Social or Environmental Policies

APUC has formal policies and procedures that support its commitment to corporate responsibility ("**CR**"). APUC's Code of Business Conduct and Ethics is the foundation of the Corporation's CR framework. As a condition of employment, all employees are required to read the Code of Business Conduct and Ethics and apply the code to their work.

Employees are required to complete a declaration annually, which confirms their compliance with and understanding of the Code of Business Conduct and Ethics. During the course of business, any compliance exceptions are reviewed and managed promptly.

APUC's businesses have safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into their respective Safety Mission Statements and Employee manuals.

APUC has an Environmental, Health and Safety Group that reports independently to the President of the appropriate region. This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.

APUC is actively involved in CR. Using the Global Reporting Initiative ("**GRI**"), the Corporation formally tracks several GRI indicators, and in 2014 began publishing a CR report. With CR as an element of the Corporations's decision making the Corporation reduces liability for investors, increases morale and engagement of employees, creates an environmentally cleaner community, and enhances the partnership with all of its stakeholders.

CR is often defined by a company's philosophy to operate in an economically, socially and environmentally sustainable manner, while recognizing the interests of its stakeholders. APUC has environmentally supportive programs in place that promote energy efficiency and responsible water usage, help facilitate habitat conservation to minimize impact, monitor greenhouse gas emissions, and promote waste reduction and spill prevention. The economic branch of the Corporation's CR efforts incorporates local spending, local hiring, and operational efficiency. The Corporation's commitment to people is demonstrated through our employee training, learning and development programs, organizational improvements, emergency management, health and safety policies, diversity in the workplace, and community involvement. The Corporation believes this philosophy will contribute to a sustainable future for its investors, communities, environment, customers, employees, governments, and business partners.

## 3.11 Credit Ratings

APUC and its subsidiaries maintain the following credit ratings by the Rating Agencies[1]:

| | S&P | | DBRS | |
|---|---|---|---|---|
| | 2015 | 2014 | 2015 | 2014 |
| APUC - Issuer rating | BBB | BBB | BBB(low) | BBB(low) |
| APUC - Preferred Shares | P-3 [3] | P-3 [3] | Pfd-3 (low) | Pfd-3 (low) |
| APCo - Issuer rating | BBB | BBB | BBB (low) | BBB (low) |
| APCo - Senior unsecured debt | BBB | BBB | BBB (low) | BBB (low) |
| Liberty Utilities | BBB | BBB | - | - |
| LU GP1 - Issuer rating[2] | - | - | BBB (high) | BBB (high) |
| LU GP1 - Senior unsecured notes | - | - | BBB (high) | BBB (high) |
| CalPeco - Senior unsecured notes | - | - | BBB | BBB |

[1] Credit ratings are intended to provide investors with an independent measure of the credit quality of an issue of securities. Credit ratings are not a recommendation to buy, sell or hold securities of APUC and do not comment as to market price or suitability for a particular investor. There can be no assurance that a rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn at any time by the rating agency.

[2] Issued by LU Gp1 and guaranteed by Liberty Utilities.

[3] P-3 rating is equivalent to a BB rating on S&P's global preferred share rating scale

### DBRS

DBRS rates debt instruments and issuers with ratings ranging from "AAA", which represents debt instruments and issuers of the highest credit quality, to "D", which represent debt instruments for which a company has not made a scheduled payment of interest or principal or has made it clear it will miss such a payment in the near future. Long-term debt rated "BBB" category by DBRS are of adequate credit quality. Protection of interest and principal is considered acceptable, but the entity is fairly susceptible to adverse changes in financial and economic conditions, or there may be other adverse conditions present which reduce the strength of the entity and its rated securities. A DBRS rating may be modified by the addition of a "(high)" or "(low)" to indicate the relative standing within a particular rating category. The absence of either a "(high)" or "(low)" designation indicates that the rating is in the "middle" of the category.

According to the DBRS rating system, preferred shares rated Pfd-3 are of adequate credit quality. While protection of dividends and principal is still considered acceptable, the issuing entity is more susceptible to adverse changes in financial and economic conditions, and there may be other adverse conditions present which detract from debt protection. "High" or "low" grades are used to indicate the relative standing within a rating category. The absence of either a "high" or "low" designation indicates the rating is in the middle of the category.

On February 10, 2016, DBRS Limited ("DBRS") placed APCo's 'BBB (low)' Issuer Rating and APUC's 'Pfd-3 (low)' Preferred Shares ratings 'Under Review with Developing Implications'. DBRS also placed the 'BBB (high)' Issuer Rating, 'BBB (high)' Series A, Series C, and Series D Senior Notes ratings of LU GP1, a special purpose financing entity of Liberty Utilities and the 'BBB (low)' Issuer Rating and 'BBB (low)' Senior Unsecured Debentures ratings of APCo 'Under Review with Developing Implications'. The ratings actions reflect DBRS's view that the Acquisition will have a relatively neutral impact on the business risk assessments of APUC and its subsidiaries, and that the impact on the financial risk assessment was at the time of the ratings actions uncertain since the financing plan had not been finalized. For APCo, the DBRS announcement states that the credit quality of APCo could be indirectly affected should APUC's credit profile significantly deteriorate following the Acquisition. This reflects DBRS's view that APCo relies partly on APUC to provide equity injections to maintain key financial metrics within the rating category and that if APUC's debt levels increase significantly following the Acquisition, the Corporation may require more dividends from APCo to service its debt. DBRS indicated that it will review the finalized financing plan and further review any potential impact of the Acquisition on each entity's credit profile.

### S&P

S&P rates debt instruments and issuers with ratings ranging from "AAA", which represent the greatest ability of an obligor to meet its financial commitment, to "D", which represents an obligor in payment default. An obligor rated 'BBB' has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating may be modified by the addition of a plus "+" or minus "-" sign to show relative standing within the major rating categories. The absence of either a plus "+" or minus "-" sign indicates that the rating is in the "middle" of the category.

According to the S&P rating system, preferred shares rated P-3 are regarded as having significant speculative characteristics. While such securities will likely have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposures to adverse conditions. The ratings from P-1 to P-5 may be modified by "high" and "low" grades which indicate relative standing within the major rating categories.

On February 9, 2016, S&P revised its ratings outlook on APUC and its subsidiaries to negative from stable, while affirming the existing ratings for each of such companies, including the 'BBB' long-term corporate rating on APUC. S&P indicated that the negative outlook reflects the execution risk associated with the Acquisition and the potential for lower ratings stemming from the limited ability to absorb weaker financial performance. The revised outlook also reflects S&P's expectation that certain of The Corporation's consolidated pro forma credit metrics will materially weaken due to the Offering (S&P treats the Debentures represented by Instalment Receipts as debt until they are converted into Common Shares).

## 4. ENTERPRISE RISK MANAGEMENT

An enterprise risk management ("**ERM**") framework is embedded across the organization that systematically and broadly identifies, assesses, and mitigates the key strategic, operational, financial, and compliance risks that may impact the achievement of our objectives. APUC's ERM policy details the risk management processes, risk appetite, and risk governance structure which clearly establishes accountabilities for managing risk across the organization. In 2015, the Risk and Insurance Management Society (RIMS) recognized APUC's ERM program for achieving sustainable and repeatable ERM practices.

As part of the risk management processes, risk registers have been developed across the organization through ongoing risk identification and risk assessment exercises facilitated by APUC's internal ERM team. Key risks and associated mitigation strategies are reviewed by the Executive Risk Steering Committee on a monthly basis and presented to the Board on a quarterly basis. The key risk categories assessed include: safety, environment, natural disasters, security (physical and cyber), operations, organizational effectiveness, contracts, budget, capital projects, return on M&A activity, markets, liquidity, financial reporting, strategic, and regulatory.

Risks are assessed consistently across the organization using a common risk matrix to assess impact and likelihood. Financial, reputation and safety implications are considered when determining the impact of a potential risk. Risk treatment priorities are established based upon these risk assessments and incorporated into the development of APUC's strategic plans.

The development and execution of risk treatment plans are actively monitored by the ERM team through a centralized risk register software application. APUC's internal audit team is responsible for conducting audits to validate and test the effectiveness of controls for the key risks. Audit findings are discussed with business owners and reported to the Board's audit committee (the "**Audit Committee**")on a quarterly basis. All material changes to exposures, controls or treatment plans of key risks are reported to the ERM team, Executive Risk Steering Committee, and the Board for consideration.

APUC's ERM framework follows the guidance of ISO 31000;2009. The Board oversees management to ensure the risk governance structure and risk management processes are robust, and that APUC's risk appetite is thoroughly considered in decision-making across the organization.

## 4.1 Treasury Risk Management

### 4.1.1 Foreign Currency Risk

Currency fluctuations may affect the cash flows APUC would realize from its consolidated operations, as certain APUC subsidiary businesses sell electricity or provide utility services in the United States and receive proceeds from such sales in U.S. dollars. Such APUC businesses also incur costs in U.S. dollars. At the current exchange rate, approximately 81% of EBITDA in 2015 and 80% of cash flow from operations is generated in U.S. dollars. APUC estimates that, on an unhedged basis, a $0.10 increase in the strength of the U.S. dollar relative to the Canadian dollar would result in a net impact on U.S. operations of approximately $30.6 million ($0.12 per share) on an annual basis.

In light of the currency profile of its operations, APUC pays its dividend in U.S. dollars. APUC further manages currency risk through the matching of U.S. long term debt to finance its U.S. operations, thereby creating a natural hedge for the operating profit vis a vis financing cost. APUC's policy is not to utilize derivative financial instruments for trading or speculative purposes. APUC may from time to time enter into short term foreign currency derivative contracts to hedge exposure of anticipated transactions denominated in a foreign currency. Entering into hedging arrangements could result in limiting positive impacts if hedging had not been used.

There are additional exchange rate consideration related to the proposed Acquisition of Empire. The cash consideration for the Acquisition is required to be paid in U.S. dollars, while the Offering which represents a significant portion of the funds which are ultimately to be used to finance the Acquisition, are denominated in Canadian dollars. As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the Final Instalment on the Offering will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Acquisition ultimately obtained by APUC under the Offering. This could cause a failure to realize the anticipated benefits of the Acquisition. To mitigate this risk, the Corporation has converted the initial amounts received from the Offering into U.S. dollars. The Corporation is evaluating the merits of entering into future hedging agreements to mitigate the risk on all or a portion of the remaining funds to be received. Should the Acquisition not close and the Corporation is required to repay the initial Instalment received on the Debentures it will have to translate the funds on the initial Instalment Receipt translated into U.S. dollars back to Canadian Dollars.

### 4.1.2 Market Price Risk

The Distribution Group is not exposed to market price risk as rates charged to customers are stipulated by the respective regulatory bodies.

The Generation Group predominantly enters into long term PPAs for its generation assets and hence is not exposed to market risk for this portion of its portfolio. Where a generating asset is not covered by a power purchase contract, the Generation Group may seek to mitigate market risk exposure by entering into financial or physical power hedges requiring that a specified amount of power be delivered at a specified time in return for a fixed price. There is a risk that the Corporation is not able to generate the specified amount of power at the specified time resulting in production shortfalls under the hedge that then requires the Corporation to purchase power in the merchant market. To mitigate the risk of production shortfalls under hedges, the Generation Group generally seeks to structure hedges to cover less than 100% of the anticipated production, thereby reducing the risk of not producing the minimum hedge quantities. Nevertheless, due to unpredictability in the natural resource or due to grid curtailments or mechanical failures, production shortfalls may be such that the Generation Group may still be forced to purchase power in the merchant market at prevailing rates to settle against a hedge.

Hedges currently put in place by the group along with residual exposures to the market are detailed below:

On May 15, 2012, the Generation Group entered into a financial hedge, which expires December 31, 2016, with respect to its Dickson Dam Hydro Facility located in the Western region. The financial hedge is structured to hedge 75% of the facility's expected production volume against exposure to the Alberta Power Pool's current spot market rates. The annual unhedged production based on long term projected averages is approximately 16,000 MW-hrs annually. Therefore, each U.S. $10.00 per MW-hr change in the market prices in the Western region would result in a change in revenue of U.S. $0.2 million on an annualized basis.

The July 1, 2012 acquisition of Sandy Ridge Wind Facility included a financial hedge, which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 72% of the Sandy Ridge Wind Facility's expected production volume against exposure to PJM Western Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 44,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $0.4 million for the year.

The December 10, 2012 acquisition of Senate Wind Facility included a physical hedge, which commenced on January 1, 2013 for a 15 year period. The physical hedge is structured to hedge 64% of the Senate Wind Facility's expected production volume against exposure to ERCOT North Zone current spot market rates. The annual unhedged production based on long term projected averages is approximately 188,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in the market prices would result in a change in revenue of about U.S. $1.9 million for the year.

The December 10, 2012 acquisition of the Minonk Wind Facility included a financial hedge, which commenced on January 1, 2013 for a 10 year period. The financial hedge is structured to hedge 73% of the Minonk Wind Facility's expected production volume against exposure to PJM Northern Illinois Hub current spot market rates. The annual unhedged production based on long term projected averages is approximately 186,000 MW-hrs annually. Therefore, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $1.9 million for the year.

Under each of the above noted hedges, if production is not sufficient to meet the unit quantities under the hedge, the shortfall must be purchased in the open market at market rates. The effect of this risk exposure could be material but cannot be quantified as it is dependent on both the amount of shortfall and the market price of electricity at the time of the shortfall.

In addition to the above noted hedges, from time to time the Generation Group enters into short-term derivative contracts (with terms of one to three months) to further mitigate market price risk exposure due to production variability. As at December 31, 2015, the Generation Group had entered into hedges with a cumulative notional quantity of 10,480 MW-hrs.

The January 1, 2013 acquisition of the Shady Oaks Wind Facility included a power sales contract, which commenced on January 1, 2013 for a 20 year period. The power sales contract is structured to hedge the preponderance of the Shady Oaks Wind Facility's production volume against exposure to PJM ComEd Hub current spot market rates. For the unhedged portion of production based on expected long term average production, each U.S. $10 per MW-hr change in market prices would result in a change in revenue of about U.S. $0.5 million for the year.

### 4.1.3 Credit/Counterparty Risk

APUC and its subsidiaries are subject to credit risk through its long term power purchase contracts, trade receivables, derivative financial instruments and short term investments. APUC has processes in place to monitor and evaluate this risk on an ongoing basis including background credit checks and security deposits from new customers.

APUC does not believe the credit risk of default by counterparties to its long term power purchase contracts to be significant, as approximately 83.9% of the Generation Group's revenues are earned from large utility customers having a credit rating of Baa1 or better by Moody's or BBB+ or higher by S&P Rating Services. The following chart sets out the Generation Group's significant customers, their credit ratings and percentage of total revenue associated with the customer:

| Counterparty | Credit Rating [1] | Approximate Annual Revenues | Percent of Revenue |
|---|---|---|---|
| Generation Group - Renewable Energy | | | |
| PJM Interconnection LLC | Aa3 | $ 40.5 | 18.2% |
| Manitoba Hydro | Aa1 | 29.4 | 13.2% |
| Hydro Quebec | Aa2 | 27.6 | 12.4% |
| Pacific Gas and Electric Company | BBB | 21.7 | 9.7% |
| Ontario Electricity Financial Corporation | Aa2 | 19.3 | 8.7% |
| US Wind Hedge Counterparty | A3 | 17.9 | 8.0% |
| Connecticut Light and Power | Baa1 | 16.7 | 7.5% |
| Commonwealth Edison | Baa1 | 13.5 | 6.1% |
| **Total – Generation Group** | | **$ 186.6** | **83.8%** |

[1] Ratings by Moody's or Standard & Poor's

The remaining revenue of the company is primarily earned by the Distribution Group. In this regard, the credit risk attributed to the Distribution Group's accounts receivable balances at the water and wastewater distribution systems total U.S. $4.6 million which is spread over approximately 104,000 connections, resulting in an average outstanding balance of approximately $40 dollars per connection.

The natural gas distribution systems accounts receivable balances related to the natural gas utilities total U.S. $53.8 million, while electric distribution systems accounts receivable balances related to the electric utilities total U.S. $26.9 million. The natural gas and electrical utilities, respectively, derive over 90% and 87% of their revenue from residential customers.

In addition to the counterparty risk related to customer sales outlined above, the Generation and Distribution Groups utilize derivative instruments as hedges of certain financial risks as discussed elsewhere in this AIF. APUC is exposed to credit risk related to counterparties to the extent those derivative instruments are in an asset position at a point in time. The company manages counterparty risk by entering into these instruments with counterparties having a credit rating of BBB- or better.

### 4.1.4 Interest Rate Risk

The majority of debt outstanding in APUC and its subsidiaries is subject to a fixed rate of interest and as such is not subject to interest rate risk. Borrowings subject to variable interest rates are as follows:

- The Corporate Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- The Generation Credit Facility is subject to a variable interest rate and had $27.3 million outstanding as at December 31, 2015. As a result, a 100 basis point change in the variable rate charged would impact interest expense by $0.3 million annually.
- The Distribution Credit Facility is subject to a variable interest rate and had no amounts outstanding as at December 31, 2015. As a result, a 100 basis point change in the variable rate charged would not impact interest expense.
- To mitigate financing risk, from time to time APUC may seek to fix interest rates on expected future financings. In the fourth quarter of 2014, the Generation Group entered into a hedge to fix the underlying interest rate for the anticipated refinancing of its $135.0 million bond maturing in July 2018. Hedge accounting treatment applies to this transaction. Consequently, changes in fair value, to the extent deemed effective, are being recorded into Other Comprehensive Income.

APUC does not actively manage interest rate risk on its variable interest rate borrowings due to the primarily short term and revolving nature of the amounts drawn.

### 4.1.5 Tax Risk and Uncertainty

Although APUC is of the view that all expenses being claimed by APUC are reasonable and that the cost amount of APUC's depreciable properties have been correctly determined, there can be no assurance that the Canada Revenue Agency ('CRA") or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to shareholders.

*Unit Exchange Transaction*

On October 27, 2009, unitholders of Algonquin Power Income Fund exchanged their trust units on a one for one basis for Common Shares (the "Unit Exchange Transaction"). As a result of the Unit Exchange Transaction, APUC recorded certain additional tax attributes to the extent management believed they were more likely than not to be realized. The excess of the carrying amount of the tax attributes assumed over the consideration paid was recorded as a deferred credit of $55.6 million on the date of the Unit Exchange Transaction (the "Transaction Date"). The deferred credit has been recognized into income as a deferred income tax recovery in relative proportion to the amount of the related tax attributes that have been utilized since the Transaction Date.

Earlier in the year APUC received correspondence from the CRA which outlined its intention to challenge the tax consequences of the Unit Exchange Transaction. The CRA was seeking to apply the acquisition of control rules through application of the general anti-avoidance rule of the Income Tax Act (Canada), the effect of which would be to deny APUC the benefit of the tax attributes it assumed as part of the Unit Exchange Transaction.

On June 26, 2015 APUC, entered into an agreement with CRA regarding a CRA proposal to reassess APUC's 2009 through 2013 income tax filings in relation to the Unit Exchange Transaction. The agreement resulted in a $16.0 million reduction in APUC's deferred tax assets and a proportional reduction of $13.3 million in deferred credits. Consequently, APUC's results for 2015 reflect a $2.7 million net non-cash charge to deferred income tax expense.

### 4.1.6 Liquidity Risk

Liquidity risk is the risk that APUC and its subsidiaries will not be able to meet their financial obligations as they become due.

Both the Generation Group and the Distribution Group have established financing platforms to access new liquidity from the capital markets as requirements arise. APUC continually monitors the maturity profile of its debt and adjusts accordingly to ensure sufficient liquidity exists to meet liabilities when due.

As at December 31, 2015, APUC and its subsidiaries had a combined $591.7 million of liquidity available under the Facilities remaining and $124.4 million of cash resulting in $716.1 million of total liquidity and capital reserves.

APUC currently pays a dividend of U.S. $0.3850 per Common Share per year. The Board determines the amount of dividends to be paid, consistent with APUC's commitment to the stability and sustainability of future dividends, after providing for amounts required to administer and operate APUC and its subsidiaries, for capital expenditures in growth and development opportunities, to meet current tax requirements, and to fund working capital that, in its judgment, ensures APUC's long-term success. Based on the level of Common share dividends paid during the year ended December 31, 2015, cash provided by operating activities exceeded common share dividends declared by 2.0 times.

The current and long term portion of debt totals approximately $1,496.1 million with maturities set out in the Contractual Obligation table. In the event that APUC was required to replace the Facilities and project debt with borrowings having less favorable terms or higher interest rates, the level of cash generated for dividends and reinvestment may be negatively impacted.

The cash flow generated from several of APUC's operating facilities is subordinated to senior project debt. In the event that there was a breach of covenants or obligations with regard to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and APUC losing its investment in such operating facility. APUC actively manages cash availability at its operating facilities to ensure they are adequately funded and minimize the risk of this possibility.

### 4.1.7 Downgrade in the Company's Credit Rating Risk

APUC has a long term consolidated corporate credit rating of BBB (flat) from Standard & Poors ("S&P) and a BBB (low) rating from DBRS Limited ("DBRS"). APCo has a BBB (low) issuer rating from DBRS. Liberty Utilities Finance GP1, a special purpose financing entity of Liberty Utilities Co has a BBB (high) issuer rating from DBRS

The ratings indicate the agencies' assessment of APUC's ability to pay the interest and principal of debt securities it issues. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. A downgrade in APUC's or its subsidiaries issuer corporate credit ratings would result in an increase in APUC's borrowing costs under its bank credit facilities and future long term debt securities issued. If any of APUC's ratings fall below investment grade (investment grade is defined as BBB- or above for S&P and BBB low or above for DBRS), APUC's ability to issue short-term debt, or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on APUC's business, cost of capital, financial condition and results of operations.

APUC mitigates this risk by actively monitoring and targeting the key credit metrics and other considerations used by the rating agencies to evaluate its ratings. No assurances can be provided that any of APUC's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

### 4.1.8 Commodity Price Risk

The Generation Group's exposure to commodity prices is primarily limited to exposure to natural gas price risk. The Distribution Group is exposed to energy and natural gas price risks at its electric and natural gas systems. In this regard, a discussion of this risk is set out as follows:

- The Sanger Thermal Facility's PPA includes provisions which reduce its exposure to natural gas price risk. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in an increase in net revenue by approximately $0.2 million on an annual basis.
- The Ahlstrom ESA includes provisions which reduce its exposure to natural gas price risk but has exposure to market rate conditions for sales above those to its primary customer. In this regard, a $1.00 increase in the price of natural gas per MMBTU, based on expected production levels, would result in a decrease in net revenue by approximately $0.1 million on an annual basis.
- The Maritime region provides short-term energy requirements to various customers at fixed rates. The energy requirements of these customers are estimated at approximately 164,000 MW-hrs in fiscal 2016, of which 141,000 MW-hrs is presently contracted. While the Tinker Hydro Facility is expected to provide the majority of the energy required to service these customers, the Maritime region anticipates having to purchase approximately 23,000 MW-hrs of its energy requirements at the ISO-NE spot rates to supplement self-generated energy should the Maritime region be able to reach the estimated 164,000 MW-hrs. The risk associated with the expected market purchases of 23,000 MW-hrs is mitigated through the use of short-term financial energy hedge contracts which cover approximately 73% of the Maritime region's anticipated purchases during the price-volatile winter months at an average rate of approximately $79 per MW-hr. For the amount of anticipated purchases not covered by hedge contracts, each $10.00 change per MW-hr in the market prices in ISO-NE would result in a change in expense of $0.1 million on an annualized basis.

The CalPeco Electric System provides electric service to the Lake Tahoe California basin and surrounding areas at rates approved by the CPUC. The CalPeco Electric System purchases the energy, capacity, and related service requirements for its customers from NV Energy via a PPA at rates reflecting NV Energy's system average costs.

The CalPeco Electric System's tariffs allow for the pass-through of energy costs to its rate payers on a dollar for dollar basis, through the ECAC mechanism, which allows for the recovery or refund of changes in energy costs that are caused by the fluctuations in the price of fuel and purchased power. On a monthly basis, energy costs are compared to the CPUC approved base tariff energy rates and the difference is deferred to a balancing account. Annually, based on the balance of the ECAC balancing account, if the ECAC revenues were to increase or decrease by more than 5%, the CalPeco Electric System's ECAC tariff allows for a potential adjustment to the ECAC rates which would eliminate the risk associated with the fluctuating cost of fuel and purchased power. The CalPeco Electric System also benefits from a revenue decoupling mechanism and a vegetation management memorandum account. The revenue decoupling mechanism decouples base revenues from fluctuations caused by weather and economic factors reducing volumetric risk for the utility. The vegetation management memorandum account allows for the tracking and pass through of vegetation management expenses, one of the largest expenses of the utility, reducing the potential for expenses to exceed the amounts allowed for in general rates.

The Granite State Electric System is an open access electric utility allowing for its customers to procure commodity services from competitive energy suppliers. For those customers that do not choose their own competitive energy supplier, Granite State Electric System provides a Default Service offering to each class of customers through a competitive bidding process. This process is undertaken semi-annually for all customers. The winning bidder is obligated to provide a full requirements service based on the actual needs of the Granite State Electric System's Default Service customers. Since this is a full requirements service, the winning bidder(s) take on the risk associated with fluctuating customer usage and commodity prices. The supplier is paid for the commodity by the Granite State Electric System which in turns receives pass-through rate recovery through a formal filing and approval process with the NHPUC on a semi-annual basis. The Granite State Electric System is only committed to the winning Default Service supplier(s) after approval by the NHPUC so that there is no risk of commodity commitment without pass-through rate recovery.

The EnergyNorth Natural Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties. The EnergyNorth Natural Gas System's portfolio of assets and its planning and forecasting methodology are approved by the NHPUC bi-annually through Least Cost Integrated Resource Plan filing. In addition, EnergyNorth Natural Gas System files with the NHPUC for recovery of its transportation and commodity costs on a semi-annual basis through the Cost of Gas ("COG") filing and approval process. The EnergyNorth Natural Gas System establishes rates for its customers based on the NHPUC approval of its filed COG. These rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the EnergyNorth Natural Gas System locks in a fixed price basis for approximately 14% of its normal winter period purchases under a NHPUC approved hedging program. All costs associated with the fixed basis hedging program are allowed to be pass-through to customers through the COG filing and the approved rates in said filing. Should commodity prices increase or decrease relative to the initial semi-annual COG rate filing, the EnergyNorth Natural Gas System has the right to automatically adjust its rates going forward in order to minimize any under or over collection of its gas costs. In addition, any under collections may be carried forward with interest to the next year's corresponding COG filing, i.e. winter to winter and summer to summer.

The Midstates Gas Systems purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the three individual State Commissions for recovery of its transportation and commodity costs through an annual Purchase Gas Adjustment ("PGA") filing and approval process. The Midstates Gas Systems establishes rates for its customers within the PGA filing and these rates are designed to fully recover its anticipated transportation and commodity costs. In order to minimize commodity price fluctuations, the Company has implemented a commodity hedging program designed to hedge approximately 25-50% of its non-storage related commodity purchases. All gains and losses associated with the hedging program are allowed to be pass-through to customers through the PGA filing and are embedded in the approved rates in said filing. Rates can be adjusted on a monthly or quarterly basis in order to account for any commodity price increase or decrease relative to the initial PGA rate, minimizing any under or over collection of its gas costs.

The Georgia (Peach State) Gas System purchases pipeline capacity, storage and commodity from a variety of counterparties, and files with the Georgia PSC for recovery of its transportation, storage and commodity costs through a monthly PGA filing process. The Peach State Gas System establishes rates for its customers within the PGA filings and these rates are designed to fully recover its anticipated transportation, storage and commodity costs. In order to minimize commodity price fluctuations, the annual Gas Supply Plan filed by the Company and approved by the PSC includes a commodity hedging program designed to hedge approximately 30% of its non-storage related commodity purchases during the winter months. All gains and losses associated with the hedging program are passed through to customers in the PGA filings and are embedded in the approved rates in such filings. Rates can be adjusted on a monthly basis in order to account for any differences in gas costs relative to the amounts assumed in the PGA filings, minimizing any under or over collection of its gas costs.

### 4.1.9 Defined Benefit Pension Plan Risk

In conjunction with recent utilities acquisitions, the Company assumed defined benefit pension and OPEB plans for qualifying employees in the related acquired businesses. The legacy plans of the electricity and gas utilities are non-contributory defined pension plans covering substantially all employees of the acquired businesses. Benefits are based on each employee's years of service and compensation. The Company also provides a defined benefit cash balance pension plan covering substantially all its new employees and current employees at its water utilities, under which employees are credited with a percentage of base pay plus a prescribed interest rate credit. The OPEB plans provide health care and life insurance coverage to eligible retired employees. Eligibility is based on age and length of service requirements and, in most cases, retirees must cover a portion of the cost of their coverage.

APUC manages the assets in its Plans by engaging professional investment managers who operate under prescribed investment policies and procedures in respect of permitted investments and asset allocations. Future contributions to the APUC's Plans are impacted by a number of variables, including the investment performance of the plans' assets and the discount rate used to value the liabilities of the plans. If capital market returns are below assumed levels, or if discount rates decrease, APUC could be required to make contributions to its Plans in excess of those currently expected.

## 4.2 Operational Risk Management

### 4.2.1 Mechanical and Operational Risks

APUC's profitability could be impacted by, among other things, equipment failure, the failure of a major customer to fulfill its contractual obligations under its PPA, reductions in average energy prices, a strike or lock-out at a facility, and expenses related to claims or clean-up to adhere to environmental and safety standards.

The Generation Group's hydro assets utilize dams to pond water for generation and if the dams burst potentially catastrophic amounts of water would flood downriver from the facility. The dams can be subjected to drought conditions and lose the ability to generate during peak load conditions, causing the facilities to fall short of either hedged or PPA committed production levels. The risks of the hydro facilities are mitigated by regular dam inspections and a maintenance program of the facility to lessen the risk of dam failure.

The Generation Group's wind assets could catch on fire and, depending on the season, could ignite significant amounts of forest or crop downwind from the wind farms. The wind units could also be affected by large atmospheric conditions (e.g. El Nino), which will lower wind levels below our PPA and hedge minimum production levels. Production risks associated with the wind turbine generators is mitigated by properly maintaining the units using long term maintenance agreements with the turbine O&M's, which provide for regular inspections and maintenance of property and liability insurance policies. Icing can be mitigated by shutting down the unit as icing is detected at the site.

The Generation Group's Thermal Energy Division uses natural gas and oil, and produce exhaust gases, which if not properly treated and monitored could cause hazardous chemicals to be released into the atmosphere. The units could also be restricted from purchasing gas/oil due to either shortages or pollution levels, which could hamper output of the facility. The mechanical and operational risks at the Thermal Energy Division are mitigated through the regular maintenance of the boiler system, and by continual monitoring of exhaust gases. Fuel restrictions can be hedged somewhat by long term purchases.

All of the Generation Group's electric generating stations are subject to mechanical breakdown. The risk of mechanical breakdown is mitigated by properly maintaining the units and by regular inspections.

The Distribution Group's water and wastewater distribution systems operate under pressurized conditions within pressure ranges approved by regulators. Should a water distribution network become compromised or damaged, the resulting release of pressure could result in serious injury or death to individuals or damage to other property.

The Distribution Group's electric distribution systems are subject to storm events, usually winter storm events, whereby power lines can be brought down with the attendant risk to individuals and property. In addition, in forested areas, power lines brought down by wind can ignite forest fires which also bring attendant risk to individuals and property.

The Distribution Group's natural gas distribution systems are subject to risks which may lead to fire and/or explosion which may impact life and property. Risks include third party damage, compromised system integrity, type/age of pipelines, and severe weather events.

These risks are mitigated through the diversification of APUC's operations, both operationally (the Generation and Distribution Groups) and geographically (Canada and U.S.), the use of regular maintenance programs, including pipeline safety programs and compliance programs, and maintaining adequate insurance and the establishment of reserves for expenses.

### 4.2.2 Regulatory Risk

Profitability of APUC businesses is in part dependent on regulatory climates in the jurisdictions in which those businesses operate. In the case of some Generation Group's hydroelectric facilities, water rights are generally owned by governments that reserve the right to control water levels which may affect revenue.

The Distribution Group's facilities are subject to rate setting by state regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by state regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. As a strategy to mitigate, the Distribution Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expense. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Distribution Group regularly works with its governing authorities to manage the affairs of the business employing both local state level and corporate resources.

*Condemnation Expropriation Proceedings*

The Distribution Group's distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Determination of such fair and just compensation is undertaken pursuant to a legal proceeding and, therefore, there is no assurance that the value received for assets taken will be in excess of book value. In 2014, the Company entered into an agreement to acquire Western Water Holdings LLC, which is the parent company of the regulated water distribution utility Park Water Company. The Park Water Company owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Mountain Water Company is the water utility in Western Montana serving the municipality of Missoula owned by Park Water Company.

Mountain Water Company is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water. The City's right to take Mountain Water is currently on appeal before the Montana Supreme Court, which is set to hear the appeal on April 22, 2016. If the City of Missoula prevails on appeal and ultimately takes possession of Mountain Water, the compensation to be paid by the City of Missoula for such taking will be the value of the utility (determined by the valuation commissioners on November 17, 2015 to be U.S. $88.6 million) plus accrued interest and attorney's fees as determined by the Montana court. Mountain Water is seeking U.S. $4.8 million in attorney's fees and U.S. $16.0 million in interest. The City of Missoula opposes an award of attorney's fees and interests as requested by Mountain Water. On December 22, 2015, various developers filed a Petition for Declaratory and Other Relief in Missoula County District Court against Mountain Water and the City of Missoula. The lawsuit pertains to Funded By Others ("FBO") contracts between each developer and Mountain Water. Under those FBO contracts, the developers paid for facilities to provide water service. Mountain Water agreed to refund those developer advances under the FBO contracts over a 40 year period. These FBO contracts represent a liability of U.S. $22.0 million on the balance sheet of Mountain Water. While there is no allegation of breach by Mountain Water under the FBO contracts, the developers are seeking to enforce these refunds should the utility be transferred to the city. That lawsuit is ongoing and is in the early stages of litigation. In addition, the Montana Public Service Commission ("Montana PSC") has asserted that the indirect change of control of Mountain Water required its approval and is, therefore, investigating potential changes to the rates of Mountain Water. Montana PSC has also expressed an intention to seek penalties against Mountain Water. The Montana PSC has acknowledged that it has no express authority over the acquisition transaction under statute, but has asserted that such authority should be implied. These matters are in the early stages.

On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases. The first phase will determine the necessity of the taking. The second phase will involve the valuation of the utility assets. If the Town of Apple Valley is successful in the right to take proceeding, a second phase will be held to determine the fair market value of Apple Valley. At present, a trial setting conference has been set for July 7, 2016. The matter is expected to take two to three years to resolve. The condemnation action has potential financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Apple Valley's assets by a jury if so elected by either party, along with a determination of interest and attorney's fees by the court.

### 4.2.3 Asset Retirement Obligations

APUC and its subsidiaries complete periodic reviews of potential asset retirement obligations that may require recognition. As part of this process, APUC and its subsidiaries consider the contractual requirements outlined in their operating permits, leases, and other agreements, the probability of the agreements being extended, the ability to quantify such expense, the timing of incurring the potential expenses, as well as other factors which may be considered in evaluating if such obligations exist and in estimating the fair value of such obligations.

The Distribution Group's facilities are operated with the assumption that their services will be required in perpetuity and there are no contractual decommissioning requirements. In order to remain in compliance with the applicable regulatory bodies, the Distribution Group has regular programs at each facility to ensure its equipment is properly maintained and replaced on a cyclical basis. These costs can generally be included in the facility's rate base and thus the Distribution Group expects to be allowed to earn a return on such investment.

In conjunction with recent acquisitions and developed projects, the Company assumed certain asset retirement obligations. The asset retirement obligations mainly relate to legal requirements for: (i) removal of wind facilities upon termination of land leases; (ii) cut (disconnect from the distribution system), purge (clean of natural gas and PCB contaminants), and cap gas mains within the gas distribution and transmission system when mains are retired in place, or dispose of sections of gas main when removed from the pipeline system; (iii) clean and remove storage tanks containing waste oil and other waste contaminants; and (iv) remove asbestos upon major renovation or demolition of structures and facilities.

### 4.2.4 Environmental Risks

APUC and its subsidiaries face a number of environmental risks that are normal aspects of operating within the renewable power generation, thermal power generation, and utilities business segments, which have the potential to become environmental liabilities. Many of these risks are mitigated through the maintenance of an adequate insurance program, which includes property, equipment breakdown, environmental, and liability policies.

The Generation Group's ongoing operations and historic activities are subject to various environmental laws and regulations and are regulated by federal agencies such as the United States Environmental Protection Agency, FERC, NERC, Environment Canada, Fisheries and Oceans Canada; and State/Provincial Agencies, such as the New York State Department of Environmental Conservation ("NYSDEC"), California Air Resource Board, Connecticut Department of Environmental Protection ("CDEP"), Illinois Department of Environmental Protection ("IDEP'), Pennsylvania Game Commission ("PGC"), Alberta Environment, Manitoba Conservation, Ontario Ministry of the Environment, Ontario Ministry of Natural Resources, among others. Power generation facilities generate air emissions, noise, potential for flooding, spill risk, possible disruption of protected wildlife, along with the generation of industrial wastewater and certain amounts of hazardous wastes.

The Distribution Group faces environmental risks that are normal aspects of operating within its business segment. The primary environmental risks associated with the operation of an electrical distribution system are related to potential accidental release of mineral oil to the environment from non-operational events and the management of hazardous and universal waste in accordance with the various Federal, State and local environmental laws. Like most other industrial companies, the Distribution Group generates some hazardous wastes as a result of its operations. Under Federal and State Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred.

In order to monitor and mitigate these risks and to remain within the regulatory requirements appropriate for these assets, the Generation and Distribution Groups investigate promptly all reported accidental releases to take all required remedial actions and manages hazardous waste and universal waste streams in accordance with the applicable Federal and State Legislation.

The primary risks associated with the operation of gas distribution systems are related to uncontrolled natural gas releases, equipment damage by construction equipment/third parties or severe weather events. The gas distribution assets are regulated by the Pipeline Hazardous Material Safety Administration (PHMSA) under the United States Department of Transportation and their respective State regulations in which the assets are located. Natural Gas Distribution Systems are subject to detailed inspections by State Regulatory Agencies to ensure adherence to applicable regulations. State Regulator Agencies review the Company's policies in reference to operation and maintenance, construction, training, emergency response, reporting, contractor management and measurements. The Distribution Group monitors all aspects of pipeline safety and quickly mitigates any identified concerns.

The primary risks associated with the operation of power generation facilities are related to uncontrolled contaminant releases (or above the permitted limits), not being in continued compliance with permits and licenses obligations such as, continuous emissions monitoring, periodic reporting/source testing, general performance/operating conditions, operations adjustments (wind projects) resulting from post construction wildlife mortality monitoring, dam safety, potential accidental release of mineral oil or other hazardous materials to the environment.

The Distribution Group's ongoing operations and historic activities are subject to various federal, state and local environmental laws and regulations and are regulated by agencies such as the United States Environmental Protection Agency, the New Hampshire Department of Environmental Services ("NHDES"). Similar to other industrial companies, the gas and electric distribution utilities generate certain hazardous wastes. Under federal and state Superfund laws, potential liability for historic contamination of property may be imposed on responsible parties jointly and severally, without fault, even if the activities were lawful when they occurred. In the case of regulated utilities these costs are often allowed in rate case proceedings to be recovered from rate payers over a specified period.

Prior to their acquisition by the Distribution Group, the EnergyNorth Gas Utility, the Granite State Electric Utility, and the New England Gas System were named as potentially responsible parties for remediation of several sites at which hazardous waste is alleged to have been disposed as a result of historic operations of Manufactured Gas Plants ("MGP") and related facilities. The Distribution Group is currently investigating and remediating, as necessary, those MGP and related sites where it is the lead project manager in accordance with plans submitted to the NHDES. The Distribution Group believes that obligations imposed on it because of those sites will not have a material impact on its results of operations or financial position.

The Distribution Group estimates the remaining undiscounted and unescalated cost of these MGP-related environmental clean-up activities will be $78.5 million which, at discount rates ranging from 2.5% to 4.2%, represents $71.5 million on a discounted basis, as the Distribution Group's estimate of costs for known issues that has been accrued at December 31, 2015. By rate orders, the Regulator provided for the recovery of site investigation and remediation costs and accordingly, at December 31, 2015 the Company has reflected a regulatory asset of $116.7 million for the remediation of the MGP and related sites.

APUC's policy is to record estimates of environmental liabilities when they are known or considered probable and the related liability is estimable.

### 4.2.5 Cycles and Seasonality Risk

Please see "*Description of the Business – Cycles and Seasonality*" for a detailed description and discussion of this risk.

### 4.2.6 Development and Construction Risk

The Generation Group actively engages in the development and construction of new power generation facilities. The current pipeline of projects either currently in construction or in development is $1.8 billion and are mainly renewable solar and wind projects. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the company's overall performance. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavorable permitting results or delays emanating from State, Provincial or Federal agency interface, construction delays or cost overruns, equipment performance outside of expectations, and land owner disputes. The Generation Group mitigates these risks through its due diligence processes, sound project management principals and appropriate contingency plans and reserves.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects, the Generation Group relies on financing from third party Tax Equity Investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked. The Amherst Wind Project in Ontario is currently the subject of an appeal to the ERT for which a decision is expected in April 2016. If the ERT finds that the project will cause serious and irreversible harm to the environment or human health, the tribunal has the authority to revoke the provincial environmental permit. If the ERT has concerns, the project would expect to be given the opportunity to make submissions or changes to the project to address the tribunals concerns.

### 4.2.7 Obligations to Serve

The Distribution Group may have facilities located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term.

Accordingly, the Distribution Group may be required to solicit additional capital or obtain additional borrowings to finance these future construction obligations.

### 4.2.8 Litigation risks and other contingencies

Please see "*Legal Proceedings and Regulatory Actions - Part 9. Legal Proceedings and Regulatory Actions*" for a detailed description and discussion of this risk.

## 4.3 Regulatory Climate and Permitting Risks

Profitability of APUC's businesses is in part dependent on regulatory climates in the jurisdictions in which it operates.

*The Generation Group*

In the case of some APCo hydroelectric generating facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The failure to obtain all necessary licenses or permits, including renewals thereof or modifications thereto, may adversely affect cash generated from operating activities.

In the United States, FERC issues licenses for the construction, operation and maintenance of hydroelectric generating facilities. Hydroelectric generating facilities are required to be licensed or have valid exemptions from FERC. Failure to maintain such licenses, including amendments or modifications thereto, may result in the owner being unable to operate the licensed facility and could adversely affect cash generated from operating activities.

There are two different mechanisms by which APCo's generating facilities sell power. They either sell power to a utility under a PPA, wherein the price is tied to the market or to the Avoided Cost, or they sell power directly into the market at market-based rates. As noted in Section 3.1.1(ii), the Generation Group's generators are either self-certified as a QF or as a EWG. Each generator sells power from its project in up to three ways: (1) If the facility is a QF, it may sell power at a rate that equals the utility purchaser's Avoided Costs or at a negotiated or market-based or tariff rate; (2) If the facility is an EWG or a QF with a capacity greater than 20 MW with MBR Authority, it may sell its power at a rate that equals a market-based rate or a rate negotiated between a buyer or seller. In order to sell power at a rate equal to the utility's Avoided Cost, the facility must maintain QF status; (3) Absent QF status, in order to maintain authority to sell power, it must either sell at market-based rates, or make sales at cost-based rates as a regulated utility. If a facility loses EWG status, it will be regulated as a public utility and not afforded certain waivers of PUHCA and FERC's regulations otherwise applicable to EWGs

*The Distribution Group*

The Distribution Group's facilities are subject to rate setting by State regulatory agencies. The time between the incurrence of costs and the granting of the rates to recover those costs by State regulatory agencies is known as regulatory lag. As a result of regulatory lag, inflationary effects may impact the ability to recover expenses, and profitability could be impacted. As a strategy to mitigate, the Distribution Group seeks to obtain approval for regulatory constructs in the states in which it operates to allow for timely recovery of operating expense. A fundamental risk faced by any regulated utility is the disallowance of costs to be placed into its revenue requirement by the utility's regulator. To the extent proposed costs are not allowed into rates, the utility will be required to find other efficiencies or cost savings to achieve its allowed returns.

The Distribution Group regularly works with its governing authorities to manage the affairs of the business employing both local state level and corporate resources.

*Condemnation Expropriation Proceedings*

The Distribution Group's water, wastewater, electricity and natural gas distribution systems could be subject to condemnation or other methods of taking by government entities under certain conditions. Any taking by government entities would legally require just and fair compensation be paid to the Distribution Group and the Distribution Group believes such compensation would reflect fair market value for any assets that are taken. Notwithstanding, the determination of such fair and just compensation will be undertaken pursuant to a legal proceeding and therefore there is no assurance that the value received for assets taken will be in excess of book value.

Mountain Water is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water. The City's right to take Mountain Water is currently on appeal before the Montana Supreme Court. The Commissioners' award as part of the condemnation proceeding established the value of Mountain Water's assets at US$88.6 million. It is believed that Mountain Water would also be entitled to reimbursement of attorney's fees plus payment of interest accruing at the rate of 10% per annum since May 2014 under Montana statutes. Accrued interest is currently estimated to be US$14 million. The Commissioners' award of US$88.6 million and the final award ordered by the Missoula District Court also are subject to appeal to the Montana Supreme Court. The City of Missoula has contested payment of interest in the condemnation proceeding. If the City of Missoula ultimately takes possession of Mountain Water, the compensation to be paid by the City of Missoula for such taking will be the value of the utility plus accrued interest and attorney's fees as determined by the Montana court.

On December 22, 2015, various developers filed a Petition for Declaratory and Other Relief in Missoula County District Court against Mountain Water and the City of Missoula. The lawsuit pertains to FBO contracts between each developer and Mountain Water. Under those FBO contracts, the developers paid for facilities to provide water service. Mountain Water agreed to refund those developer advances under the FBO contracts over a 40 year period. These FBO contracts represent a liability of US$22 million on the balance sheet of Mountain Water. While there is no allegation of breach by Mountain Water under the FBO contracts, the developers are seeking to enforce these refunds should the utility be transferred to the city. That lawsuit is ongoing and is in the early stages of litigation. In addition, the MNPSC has asserted that the indirect change of control of Mountain Water required its approval and is, therefore, investigating potential changes to the rates of Mountain Water. The MNPSC has also expressed an intention to seek penalties against Mountain Water. The MNPSC has acknowledged that it has no express authority over the acquisition transaction under statute, but has asserted that such authority should be implied. These matters are in the early stages.

On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases. The first phase will determine the necessity of the taking. The second phase will involve the valuation of the utility assets. If the Town of Apple Valley is successful in the right to take proceeding, a second phase will be held to determine the fair market value of Apple Valley. At present, a trial setting conference has been set for July 7, 2016. The matter is expected to take two to three years to resolve. The condemnation action has potential financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Apple Valley's assets by a jury, along with a determination of interest and attorney's fees by the court.

## 4.4 Safety Considerations

The operation of the facilities require adherence to safety standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these regulatory standards may expose the facilities to claims and administrative sanctions. To mitigate the risk of administrative sanctions and to minimize safety risks to employees and contractors, APUC works continuously with all employees to ensure the development and implementation of a progressive, proactive safety culture within all operations. APUC has multiple active safety committees operating with each operating unit and has a dedicated staff to ensure that the existing safety program is continuously improving.

## 4.5 Labour Relations

While labour relations have been stable to date and there have not been any disruptions in operations as a result of labour disputes with employees, the maintenance of a productive and efficient labour environment without disruptions cannot be assured.

*Generation Group*

All employees of APCo and their material subcontractors are non-unionized. During 2015 five employees at the Tinker Hydro Facility were represented by a union. Those employees filed a Declaration to Terminate Bargaining Rights from the International Brotherhood of Electrical Workers (the "IBEW Union"), Local 37 on November 13, 2015. A representation vote was held at the Tinker Hydro Facility on January 12, 2016 and A Declaration Terminating Bargaining Rights was granted on January 28, 2016.

*Distribution Group*

In California, 63 employees at the CalPeco Electric System are unionized. The current collective bargaining agreement with the IBEW Union was renegotiated in August 2014 for a term of three years, until August 2017. The CalPeco Electric System has good relations with the IBEW Union. The Corporation acquired Park Water in January 2016 with water system operations in California and Montana. None of the employees of the California or Montana water system operation are represented by a union.

In Missouri, there is one union contract with the IBEW Union covering 42 employees at the Midstates Gas System. The current collective bargaining agreement with the IBEW Union was renegotiated in June 2013 for a four year term expiring in June 2017. The Midstates Gas System has good relations with the IBEW Union.

In New Hampshire, there are currently five union contracts. The United Steelworkers of America ("Steelworkers") represent approximately 95 employees working in field operations in the gas distribution business. Their contract will expire in April 2016. In the electric business there are two IBEW Union locals representing approximately 34 field employees. The contracts for these groups will expire in March 2018. There are also 2 engineers in the Utility Workers Union of America ("UWUA") and their contract will expire in May 2017. The Steelworkers also represent the Customer Service representatives, currently with

41 members, and the 5 employees working out of the Keene, NH location. Their contracts expire in February 2017 and April 2019 respectively.

In Massachusetts, there are two union contracts with the UWUA. They currently represent 67 gas operations employees. This agreement expires in April 2017. The UWUA also represents the Customer Service representatives, a group of ten employees. This contract will expire in May 2017.

All employees at the water and/or wastewater systems in Arizona, Arkansas, California, Montana and Texas are non-union.

All employees at the natural gas systems in Georgia, Illinois, and Iowa are non-union.

## 4.6 Dependence Upon Key Customers

### (i) Generation Group

The customers of the Generation Group's facilities are primarily large utilities. See the summaries of the contracts in Schedules A and B. If, for any reason, such customers were unable to fulfill their contractual obligations under the PPAs, cash flow available to shareholders of APUC would decline.

### (ii) Distribution Group

The customers of the Distribution Group are primarily residential. Commercial, industrial and all other non-residential customers make up less than 40% of gross revenues, with no single customer accounting for a significant portion of gross revenues. As such, the Distribution Group is not dependent upon a few key customers.

## 4.7 Potential Conflicts of Interest

On December 21, 2009, an agreement was reached to internalize management. Since then, management of APUC has been conducted by officers of APUC. In addition, most other business associations between APUC and the Senior Executives have been resolved. See "*Description of the Business - Business Associations with APMI and Senior Executives*" While there may be situations in which conflicts of interest arise between the Senior Executives and APUC in relation to the interests of APUC, APUC has policies in place to deal with potential conflicts of interest.

## 4.8 Construction / Development Risk

At any given time the Corporation is involved in various construction activities. The Generation Group actively engages in the development and construction of new power generation facilities and has a current pipeline of projects either currently in construction or in development of $1.8 billion (mainly renewable solar and wind projects). The Transmission Group, in partnership with Kinder Morgan, is actively engaged in the development and construction of two pipelines. Furthermore, each of the Corporation's business segments may occasionally undertake construction activities as part of normal course maintenance activities. There is always a risk that material delays and/or cost overruns could be incurred in any of the projects planned or currently in construction affecting the Corporation's overall performance. Examples of inherent risks pertaining to power generation facility development can include: technical issues with the interconnection utility, unfavourable permitting results or delays emanating from Municipal, State, Provincial or Federal agency interface, construction delays or cost overruns, currency fluctuations affecting the cost of major capital components such as turbines, equipment performance outside of expectations, land owner disputes and construction disputes which may result in the registering of liens on the Corporation's projects.

The Corporation mitigates these risks through its due diligence processes, sound project management principles, active deployment of risk analysis, management and mitigation tools and appropriate contingency plans and reserves.

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the wind facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

The amount of solar radiance will vary from the estimate set out in the initial solar studies that were relied upon to determine the feasibility of the solar facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the solar radiance, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and cash could be impacted.

For certain of its development projects the Generation Group relies on financing from third party tax equity investors. These investors typically provide funding upon commercial operation of the facility. Should certain facilities not meet the conditions required for tax equity funding, expected returns from the facilities may be impacted.

Regulatory approvals can be challenged by a number of mechanisms which vary across state and provincial jurisdictions. Such permitting challenges could identify issues that may result in permits being modified or revoked. The Amherst Wind

Project in Ontario is currently the subject of an appeal to the ERT for which a decision is expected in April 2016. If the ERT finds that the project will cause serious and irreversible harm to the environment or human health, the tribunal has the authority to revoke the provincial environmental permit. If the ERT has concerns, the project would expect to be given the opportunity to make submissions or changes to the project to address the tribunals concerns.

## 4.9 Acquisitions and Divestitures

Acquisitions of complementary businesses and technologies are a part of APUC's overall business strategy. In spite of the complementary nature of any businesses or technologies acquired, there is always a risk that services, technologies, key personnel or businesses of acquired companies may not be effectively assimilated into APUC's business or service offerings. Similarly, divestitures of businesses that are no longer viewed as being strategic to APUC's continuing operations can be an active part of APUC's overall business strategy. Divestitures may result in a reduction in total revenues and net income.

APCo and Liberty Utilities each have a transition management office ("**TMO**") that have developed standard project management and governance processes to manage its respective company integrations due to acquisitions. These processes ensure an effective organization of people, resources and time frames for a successful integration of technology, operations, asset management and business processes. The TMO uses a sound governance reporting structure which includes the participation of the Generation and Distribution Groups' senior management to ensure that the respective operations and processes are implemented in a timely and efficient manner. The governance process also includes a transparent issue resolution process which is documented and reported throughout the Generation and Distribution Groups.

The risks associated with the Company's acquisition strategy include potential difficulties inherent in acquisitions that may adversely affect the results of an acquisition and these include delays in implementation or unexpected costs or liabilities, as well as the risk of failing to realize operating benefits or synergies from completed transactions. The Company mitigates these risks by following systematic procedures for integrating acquisitions, applying strict financial metrics to any potential acquisition and subjecting the process to close monitoring and review by the Board of Directors.

### Completion of the Acquisition of Empire

The Acquisition of Empire is subject to risks which relate to the Acquisition, the Instalment Receipts, the Debentures and the post-Acquisition business and operations of the Corporation and Empire.

For the purpose of financing the Acquisition, the Company obtained Acquisition Credit Facilities of $2.2 billion (U.S. $1.6 billion) in February 2016, and completed the $1.15 billion Debentures Offering in March 2016, including the exercise of an over-allotment. On March 9, 2016, upon issuing the Debentures (see Financial Statements note 25) and receiving the First Instalment, the Company reduced the aggregate commitments under the Acquisition Credit Facilities by $360.0 million (U.S. $263.6 million).

The Company expects to fund the cash purchase price of the Acquisition and the acquisition-related expenses with a combination of some or all of the following: (i) net proceeds of the first instalment under the Debenture Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities; and (iv) existing cash on hand and other sources available to the Corporation.

### Risk Factors Relating to the Acquisition

*APUC may fail to complete the Acquisition*

The closing of the Acquisition is subject to the normal commercial risks that the Acquisition will not close on the terms negotiated (including with respect to the consideration to be paid for the common stock of Empire) or at all. The completion of the Acquisition is subject to receipt of Empire Shareholder Approval and satisfaction of the other Approval Conditions, including expiration or termination of any applicable period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 ("**HSR Act**") , Approval of the Committee on Foreign Investment in the United States ("**CFIUS**"), obtaining the approval of each of FERC, the United States Federal Communications Commission ("**FCC**") and the State Commissions and the satisfaction or waiver of certain closing conditions contained in the Acquisition Agreement, including the absence of any law or judgement that prevents, makes illegal or prohibits the consummation of the Acquisition. The failure to obtain the required approvals or satisfy or waive the conditions contained in the Acquisition Agreement may result in the termination of the Acquisition Agreement. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that APUC will complete the Acquisition in the timeframe or on the basis described herein, if at all. The termination of the Acquisition Agreement may have a negative effect on the price of the Instalment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. If the closing of the Acquisition does not take place as contemplated, the Corporation could suffer adverse consequences, including the loss of investor confidence.

The Company will be obligated to pay Empire U.S. $65.0 million if the acquisition agreement is terminated by either party due to a failure to obtain the required regulatory approvals within 18 months following execution of the acquisition agreement, or due to a final and non-appealable legal restraint that relates to the required regulatory approvals, or if Empire terminates the acquisition agreement based on a failure by the Company to perform its obligations with respect to obtaining required regulatory approvals, provided that, in each case, at the time of termination the Empire shareholder approval has been obtained and the other conditions to the Company's obligation to complete the Acquisition have been satisfied or waived (except for those conditions that by their nature are to be satisfied at the closing and are then capable of being satisfied, and those conditions that have not been satisfied as a result of a breach of the acquisition agreement by the Company).

A termination of the acquisition agreement may have a negative effect on the price of the Installment Receipts, the Debentures and the Common Shares and will result in the redemption of the Debentures. In addition, if the closing of the Acquisition does not take place as contemplated, the Company could suffer other adverse consequences, including the loss of investor confidence.

*The cash purchase price could increase*

Empire is a public company and its directors owe fiduciary duties to Empire shareholders (and other stakeholders), which may require them to consider competing offers to purchase the common stock of Empire as alternatives to the Acquisition. The Acquisition Agreement preserves the ability of the directors of Empire to accept an alternative or competing offer in certain circumstances if such offer constitutes a Superior Proposal (as defined in the Acquisition Agreement). If a Superior Proposal to acquire Empire is made, and if the Superior Proposal results in Empire's board of directors making an Adverse Recommendation Change, if requested by APUC, Empire and its Representatives are required to negotiate in good faith with APUC regarding any revisions to the Acquisition Agreement committed to in writing by APUC, which could result in an increase to the cash purchase price of the Acquisition or to other terms and conditions of the Acquisition.

*Length of time required to complete the Acquisition is unknown*

As described above under "APUC may fail to complete the Acquisition", the closing of the Acquisition is subject to the receipt of required Empire Shareholder Approval and regulatory approvals and the satisfaction of other closing conditions contained in the Acquisition Agreement. There is no certainty, nor can APUC provide any assurance, as to when these conditions will be satisfied, if at all. A substantial delay in obtaining regulatory approvals or the imposition of unfavourable terms and/or conditions in such approvals could have a material adverse effect on the Corporation's ability to complete the Acquisition and on the Corporation's or Empire's business, financial condition or results of operations. In addition, in the event that such regulatory agencies imposed unfavorable terms and/or conditions on APUC or any Empire utility (including the requirement to sell or divest of certain assets or limitations on the future conduct of the combined entities), the Corporation could still be required to complete the transaction on the terms set forth in the Acquisition Agreement. APUC intends to complete the Acquisition as soon as practicable after obtaining the required Empire Shareholder Approval and regulatory approvals and satisfying the other required closing conditions.

*Foreign exchange risk*

The cash consideration for the Acquisition is required to be paid in U.S. dollars, while funds raised in the Debenture Offering, which will constitute a significant portion of the funds ultimately used to finance the Acquisition, are denominated in Canadian dollars. As a result, increases in the value of the U.S. dollar versus the Canadian dollar prior to payment of the final instalment will increase the purchase price translated in Canadian dollars and thereby reduce the proportion of the purchase price for the Acquisition ultimately obtained by APUC under the Offering, which could cause a failure to realize the anticipated benefits of the Acquisition.

In addition, the operations of Empire are conducted in U.S. dollars. Following the Acquisition, the consolidated net earnings and cash flows of APUC will be impacted to a much greater extent by movements in the U.S. dollar relative to the Canadian dollar. In particular, decreases in the value of the U.S. dollar versus the Canadian dollar following the Acquisition, could negatively impact APUC's net earnings as reported in Canadian dollars, which could cause a failure to realize the anticipated benefits of the Acquisition.

APUC may or may not enter into hedging arrangements to mitigate these exposures. The failure to enter into hedging arrangements could result in adverse impacts greater than if hedging had been used. Entering into hedging arrangements could result in limiting positive impacts if hedging had not been used.

*Significant demands will be placed on APUC as a result of the Acquisition*

As a result of the pursuit and completion of the Acquisition, significant demands will be placed on the Corporation's managerial, operational and financial personnel and systems. No assurance can be given that the Corporation's systems, procedures and controls will be adequate to support the expansion of the Corporation's operations resulting from the Acquisition. The Corporation's future operating results will be affected by the ability of its officers and key employees to manage changing business conditions and to implement and improve its operational and financial controls and reporting systems.

*Failure to pay the final instalment will negatively impact APUC's consolidated capitalization*

Completion of the Acquisition is not conditional on the completion of the Debenture Offering by the Corporation or on the Corporation obtaining financing on favourable terms or at all. If a material amount due on payment of the final instalment is not paid by holders of Instalment Receipts and the Corporation is not able to quickly realize on the Debentures pledged to secure the obligation to pay the final instalment, the Corporation will not be able to use those proceeds to repay the Acquisition Credit Facilities. As a result, it may take APUC longer than anticipated to repay the Acquisition Credit Facilities which may have a negative impact on the consolidated capitalization of APUC until such time as the Acquisition Credit Facilities have been repaid by APUC in full.

*Acquisition Credit Facilities may become unavailable*

The commitment of the lenders to enter into the Acquisition Credit Facilities is subject to certain standard conditions which may result in such facilities becoming unavailable to APUC in certain circumstances. If the Acquisition Credit Facilities become unavailable to APUC, APUC may not be able to complete the Acquisition. The inability of APUC to complete the Acquisition will result in redemption of the Debentures.

If the Acquisition Credit Facilities become unavailable to the Company, and the Company fails to obtain sufficient alternative financing, the Company may not be able to complete the Acquisition. The Company's obligation to complete the Acquisition is not conditional on the Company obtaining financing on favourable terms or at all. In the event that the Company does not have sufficient financing to complete the Acquisition, upon satisfaction of all conditions to closing, and Empire terminates the acquisition agreement as a result, the Company will be obligated to pay Empire U.S. $65.0 million, in addition to potential liability for damages.

*Alternate sources of funding that would be used to fund the Acquisition or replace the Acquisition Credit Facilities may not be available*

The cash purchase price of the Acquisition and the Acquisition-Related Expenses will be financed at the closing of the Acquisition with a combination of some or all of the following: (i) net proceeds of the first instalment under the Offering; (ii) net proceeds of any subsequent bond or other debt offerings; (iii) amounts drawn under the Acquisition Credit Facilities; and (iv) existing cash on hand and other sources available to the Corporation.

There is no guarantee that alternate sources of funding will be available to APUC or its affiliates at the desired time or at all, or on cost-efficient terms. The inability to obtain alternate sources of funding to fund the Acquisition or replace the Acquisition Credit Facilities may negatively impact the financial performance of APUC, including the extent to which the Acquisition is accretive. In addition, any movement in interest rates that could affect the underlying cost of these instruments may affect the expected accretion of the Acquisition. APUC may enter into hedging arrangements to mitigate this risk.

*APUC does not currently control Empire and its subsidiaries*

Although the Acquisition Agreement contains covenants on the part of Empire regarding the operation of its business prior to closing the Acquisition, APUC will not control Empire and its subsidiaries until completion of the Acquisition and Empire's business and results of operations may be adversely affected by events that are outside of the Corporation's control during the intervening period. Historic and current performance of Empire's business and operations may not be indicative of success in future periods. The future performance of Empire may be influenced by, among other factors, weather, economic downturns, increased environmental regulation, turmoil in financial markets, unfavourable regulatory decisions, rising interest rates and other factors beyond the Corporation's control. As a result of any one or more of these factors, among others, the operations and financial performance of Empire may be negatively affected which may adversely affect the future financial results of APUC. See "- Risk Factors Relating to the Post-Acquisition Business and Operations of the Corporation and Empire".

*APUC expects to incur significant Acquisition-Related Expenses*

APUC expects to incur a number of costs associated with completing the Acquisition. The substantial majority of these costs will be non-recurring expenses resulting from the Acquisition and will consist of transaction costs related to the Acquisition, including costs relating to the financing of the Acquisition and obtaining regulatory approval. Additional unanticipated costs may be incurred and the amounts may be material.

*Information relating to Empire has been obtained from Empire or its public disclosure record*

Although the Corporation has conducted what it believes to be a prudent and thorough level of investigation in connection with the Acquisition and the disclosure relating to Empire contained in this Prospectus, an unavoidable level of risk remains regarding the accuracy and completeness of such information. While APUC has no reason to believe the information obtained from Empire or taken from the public disclosure record is misleading, untrue or incomplete, APUC cannot assure the accuracy or completeness of such information nor can APUC compel Empire to disclose events which may have occurred or may affect the completeness or accuracy of such information but which are unknown to APUC.

**Risk Factors Relating to the Post-Acquisition Business and Operations of APUC and Empire**

*APUC will substantially increase its amount of indebtedness following the Acquisition*

As part of the Acquisition, APUC will assume all of Empire's existing debt. As a result, APUC will substantially increase its amount of indebtedness following the Acquisition and such increased indebtedness may adversely affect APUC's cash flow and ability to operate its business.

*The Acquisition and related financing, including the Offering, could result in a downgrade of the credit rating of APUC, Empire and/or their subsidiaries*

The change in the capital structure of APUC as a result of the Acquisition, the Offering and the entering into of the Acquisition Credit Facilities could cause credit rating agencies which rate the outstanding debt obligations of APUC to re-evaluate and potentially downgrade the Corporation's current credit ratings, which could increase the Corporation's borrowing costs.

The Acquisition could also result in a downgrade of the credit ratings of Empire and The Empire District Gas Company as well as significant mandatory redemptions of five outstanding series of bonds if the credit rating of either company, or of APUC as the acquiror, falls below "BB+" or lower by S&P or "Ba1" or lower by Moody's.

Should such an event occur, Empire must give written notice to the bond trustee and bondholders within five days of Empire becoming aware of a downgrade. The notice must include an offer to purchase all of the outstanding bonds. The purchase date must be at least 30 days after the notice, but not more than 60 days after the notice. The bondholder can accept or reject the offer and must deliver notice of its acceptance at least five days prior to the proposed purchase date. The bonds must be purchased at 100% of the principal amount, together with accrued and unpaid interest.

*Potential undisclosed liabilities associated with the Acquisition*

In connection with the Acquisition, there may be liabilities of Empire and its subsidiaries that the Corporation failed to discover or was unable to quantify in the due diligence which it conducted prior to the execution of the Acquisition Agreement. The discovery or quantification of any material liabilities of Empire and its subsidiaries could have a material adverse effect on the Corporation's business, financial condition, results of operations or future prospects.

The Corporation will not be obligated to close the Acquisition if (i) there are inaccuracies in the representations and warranties made by Empire in the Acquisition Agreement as to its liabilities which would reasonably be expected to have an Empire Material Adverse Effect, or (ii) if any circumstance, change or event occurs after the date of the Acquisition Agreement that would reasonably be expected to have an Empire Material Adverse Effect, subject to certain prescribed exceptions.

Following the closing of the Acquisition, Empire will have become an indirect wholly owned subsidiary of the Corporation and the full merger consideration under the Acquisition Agreement will have been paid, and the Corporation will have no further recourse (against Empire, its shareholders or any other persons) and will fully bear the risk for any inaccuracies in the information, representations or warranties provided by Empire in the Acquisition Agreement and any material liabilities of Empire and its subsidiaries that the Corporation does not discover or quantify prior to the closing of the Acquisition.

*APUC may be unable to successfully combine the businesses of APUC and Empire and realize the anticipated benefits of the Acquisition*

APUC believes that the Acquisition will provide benefits to the Corporation. However, there is a risk that some or all of the expected benefits of the Acquisition may fail to materialize, or may not occur within the time periods anticipated by the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation. The challenge of combining previously independent businesses makes evaluating the Corporation's business and future financial prospects difficult. The past financial performance of the Corporation may not be indicative of its future financial performance. In addition, any regulatory approvals required in connection with the Acquisition may include terms which could have an adverse effect on the Corporation's financial performance, including reduced revenues or investment recovery, increased competition or costs, or adverse alterations to the rate structure.

Failure to realize the anticipated benefits of the Acquisition may impact the financial performance of the Corporation, the price of its Common Shares and the ability of APUC to continue to pay dividends on its Common Shares at current rates or at all. The declaration of dividends by the Corporation is at the discretion of the Board of Directors and the Board of Directors may determine at any time to cease paying dividends.

The combination of the businesses of APUC and Empire will require the dedication of substantial effort, time and resources on the part of APUC's management which may divert management's focus and resources from other strategic opportunities and from operational matters during this process. There can be no assurance that management will be able to combine the operations of each of the businesses successfully or achieve any of the benefits that are anticipated as a result of the Acquisition. The extent to which the anticipated benefits are realized and the timing of such cannot be assured. Any inability of management to successfully combine the operations of APUC and Empire could have a material adverse effect on the Corporation's business, financial condition, results of operations or future prospects.

*APUC may not be successful in retaining the services of key personnel of Empire following the Acquisition*

APUC currently intends to retain key personnel of Empire following the completion of the Acquisition to continue to manage and operate Empire as a separate operating company. APUC will compete with other potential employers for employees, and it may not be successful in keeping the services of the executives and other employees of Empire that it needs to realize the anticipated benefits of the Acquisition. The Corporation's failure to retain key personnel to remain as part of the management team of Empire in the period following the Acquisition could have a material adverse effect on the business and operations of Empire and APUC on a consolidated basis.

*APUC is subject to risks associated with its results of operations and financing risks*

Management of APUC believes, based on its current expectations as to the Corporation's future performance (which reflects, among other things, the completion of the Acquisition), that the cash flow from its operations and funds available to it under its revolving credit facilities and its ability to access capital markets will be adequate to enable the Corporation to finance its operations, execute its business strategy and maintain an adequate level of liquidity. However, expected revenue and the costs of planned capital expenditures are only estimates. Moreover, actual cash flows from operations are dependent on regulatory, market and other conditions that are beyond the control of the Corporation. As such, no assurance can be given that management's expectations as to future performance will be realized. In addition, management's expectations as to the Corporation's future performance reflect the current state of its information about Empire and its operations and there can be no assurance that such information is correct and complete in all material respects.

The Corporation's degree of leverage could have adverse consequences for APUC, particularly if a significant portion of the Acquisition Credit Facilities are drawn to complete the Acquisition or if a significant portion of the Debentures are not converted into Common Shares by the holders thereof. The significant increase in the degree of the Corporation's leverage could, among other things, limit the Corporation's ability to obtain additional financing for working capital, investment in subsidiaries, capital expenditures, debt service requirements, acquisitions and general corporate or other purposes; restrict the Corporation's flexibility and discretion to operate its business; limit the Corporation's ability to declare dividends on its Common Shares; require APUC to dedicate a portion of cash flows from operations to the payment of interest on its existing indebtedness, in which case such cash flows will not be available for other purposes; cause ratings agencies to re-evaluate or downgrade the Corporation's existing credit ratings; expose APUC to increased interest expense on borrowings at variable rates; limit the Corporation's ability to adjust to changing market conditions; place APUC at a competitive disadvantage compared to its competitors that have less debt; make APUC vulnerable to any downturn in general economic conditions; and render APUC unable to make expenditures that are important to its future growth strategies.

The Corporation will need to refinance or reimburse amounts outstanding under the Corporation's existing consolidated indebtedness over time. There can be no assurance that any indebtedness of the Corporation will be refinanced or that additional financing on commercially reasonable terms will be obtained, if at all. In the event that such indebtedness cannot be refinanced, or if it can be refinanced on terms that are less favourable than the current terms, the ability of the Corporation to declare dividends may be adversely affected.

The ability of the Corporation to meet its debt service requirements will depend on its ability to generate cash in the future, which depends on many factors, including the financial performance of the Corporation, debt service obligations, the realization of the anticipated benefits of the Acquisition and working capital and future capital expenditure requirements. In addition, the ability of the Corporation to borrow funds in the future to make payments on outstanding debt will depend on the satisfaction of covenants in existing credit agreements and other agreements. A failure to comply with any covenants or obligations under the Corporation's consolidated indebtedness could result in a default under one or more such instruments, which, if not cured or waived, could result in the termination of distributions by the Corporation and permit acceleration of the relevant indebtedness. If such indebtedness were to be accelerated, there can be no assurance that the assets of the Corporation would be sufficient to repay such indebtedness in full. There can also be no assurance that the Corporation will generate cash flow in amounts sufficient to pay outstanding indebtedness or to fund any other liquidity needs.

*National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at Empire and its subsidiaries*

The business of Empire is concentrated in Missouri with business also conducted in Arkansas, Oklahoma and Kansas. Economic conditions in these states and in Empire's service territories could change and if they should worsen, retail customer growth rates may stagnate or decline and customers' energy usage may further decline, adversely affecting Empire's results of operations, net income and cash flows and those of the Corporation following the Acquisition.

*Developments in technology could reduce demand for electricity and gas*

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy efficient appliances and equipment. Advances in these, or other technologies, could reduce the cost of producing electricity, transporting gas or make the existing generating facilities of Empire uneconomic. In addition, advances in such technologies could reduce electrical or natural gas demand, which could negatively impact the results of operations, net income and cash flows of Empire and those of the Corporation following the Acquisition.

*Empire is exposed to increases in costs and reductions in revenue which Empire cannot control and which may adversely affect its business, financial condition and results of operations*

The primary drivers of Empire's regulated electric operating margins in any period are: (i) rates Empire can charge its customers, including timing of new rates; (ii) weather; (iii) customer growth and usage; and (iv) general economic conditions. Of the factors driving margins, weather has the greatest short-term effect on the demand for electricity for Empire's regulated business. Mild weather reduces demand and, as a result, Empire's regulated electric operating revenues. In addition, changes in customer demand due to downturns in the economy, energy efficiency or increased use of self-generation and distributed energy technologies could reduce Empire's revenues.

The primary drivers of Empire's regulated electric operating expenses in any period are: (i) fuel and purchased power expenses; (ii) operating, maintenance and repairs expense, including repairs following severe weather and plant outages; (iii) taxes; and (iv) non-cash items such as depreciation and amortization expense. Although Empire generally recovers these expenses through its rates, there can be no assurance that Empire will recover all or any part of such increased costs in future rate cases.

The primary drivers of Empire's regulated gas operating revenues in any period are: (i) rates Empire can charge its customers; (ii) weather; (iii) customer growth; (iv) the cost of natural gas and interstate pipeline transportation charges; and (v) general economic conditions. Because natural gas is heavily used for residential and commercial heating, the demand for this product depends heavily upon weather patterns throughout Empire's natural gas service territory and a significant amount of Empire's regulated natural gas revenues are recognized in the first and fourth quarters related to the heating seasons. Accordingly, Empire's natural gas operations have historically generated less revenues and income when weather conditions are warmer in the winter.

The primary driver of Empire's regulated gas operating expense in any period is the price of natural gas.

Significant increases in regulated electric and gas operating expenses or reductions in electric and gas operating revenues may occur and result in a material adverse effect on Empire's business, financial condition and results of operations.

*Energy conservation, energy efficiency, distributed generation and other factors that reduce energy demand could adversely affect Empire's business, financial condition and results of operations*

Regulatory and legislative bodies have proposed or introduced requirements and incentives to reduce energy consumption. Conservation and energy efficiency programs are designed to reduce energy demand. Unless there is a regulatory solution ensuring recovery, declining usage will result in an under-recovery of Empire's fixed costs. Macroeconomic factors resulting in low economic growth or contraction within Empire's service territories could also reduce energy demand. Any such reductions in energy demand could adversely affect Empire's business, financial condition and results of operations.

In addition, significant technological advancements are taking place in the electric industry, including advancements related to self-generation and distributed energy technologies such as fuel cells, micro turbines, wind turbines and solar cells. Adoption of these technologies may increase because of advancements or government subsidies reducing the cost of generating electricity through these technologies to a level that is competitive with Empire's current methods of generating electricity. There is also a perception that generating electricity through these technologies is more environmentally friendly than generating electricity with fossil fuels. Increased adoption of these technologies would reduce demand for Empire's electricity but would not necessarily reduce Empire's investment and operating requirements due to Empire's obligation to serve customers, including those self-generation customers whose equipment has failed for any reason to provide the power they need. In addition, self-generating customers do not currently pay a share of the costs necessary to operate Empire's transmission and distribution system. As a result, the pool of customers from whom fixed costs are recovered would be reduced, potentially resulting in under-recovery of Empire's fixed costs and upward price pressure on Empire's remaining customers. If Empire were unable to adjust Empire's prices to reflect such reduced electricity demand and any related use of net energy metering (which allows self-generating customers to receive bill credits for surplus power), Empire's business, financial condition and results of operations could be adversely affected. In addition, since a portion of Empire's costs are recovered through charges based upon the volume of power delivered, reductions in electricity deliveries will affect the timing of Empire's recovery of those costs and may require changes to Empire's rate structures.

*Empire is subject to environmental laws and the incurrence of environmental liabilities which may adversely affect Empire's business, financial condition and results of operations*

Empire is subject to extensive federal, state and local regulation with regard to air and other environmental matters. Failure to comply with these laws and regulations could have a material adverse effect on Empire's results of operations and financial position. In addition, new environmental laws and regulations, and new interpretations of existing environmental laws and regulations, have been adopted and may in the future be adopted which may substantially increase Empire's future environmental expenditures for both new and existing facilities. Compliance with current and potential future air emission standards (such as those limiting emission levels of sulfur dioxide (SO2), emissions of mercury, other hazardous pollutants (HAPS), nitrogen oxide (NOx), and carbon dioxide (CO2)) has required, and may in the future require, significant environmental expenditures. Although Empire has historically recovered such costs through Empire's regulated rates, there can be no assurance that Empire will recover all or any part of such increased costs in future rate cases. The incurrence of additional material environmental costs which are not recovered in Empire's rates may result in a material adverse effect on Empire's business, financial condition and results of operations.

*Empire is exposed to factors that can increase its fuel and purchased power expenditures, including disruption in deliveries of coal or natural gas, decreased output from its power plants, failure of performance by purchased power counterparties and market risk in its fuel procurement strategy related to its regulated electrical generating stations*

Fuel and purchased power costs are Empire's largest expenditures. Increases in the price of coal, natural gas or the cost of purchased power will result in increased electric operating expenditures. Given that Empire has a fuel cost recovery mechanism in all of its jurisdictions, Empire's net income exposure to the impact of the risks discussed above is significantly reduced. However, cash flow could still be impacted by these increased expenditures. Empire is also subject to prudency reviews which could negatively impact Empire's net income if a regulatory commission would conclude that Empire's costs were incurred imprudently.

Empire depends upon regular deliveries of coal as fuel for its Asbury, Iatan and Plum Point plants. Substantially all of this coal comes from mines in the Powder River Basin of Wyoming and is delivered to the plants by train. Production problems in these mines, railroad transportation or congestion problems, or unavailability of trains could affect delivery cycle times required to maintain plant inventory levels, causing Empire to implement coal conservation and supply replacement measures to retain adequate reserve inventories at its facilities. These measures could include some or all of the following: reducing the output of Empire's coal plants, increasing the utilization of Empire's gas-fired generation facilities, purchasing power from other suppliers, adding additional leased trains to Empire's supply system and purchasing locally mined coal which can be delivered without using railroads. Such measures could result in increased fuel and purchased power expenditures.

Natural gas is delivered to Empire's generation fleet at Riverton, State Line, and Energy Center via Southern Star Central Gas Pipeline. Although Empire has firm transportation contracts in place for a limited volume of daily natural gas deliveries, the actual delivery of natural gas can still be uncertain during winter peaking weather. The inability to procure commodity or pipeline curtailments for non-firm delivery causes Empire to either rely on fuel oil as a back-up fuel for generation at State Line Unit No. 1 or Energy Center units, and/or limit the generation offered into the SPP IM from State Line Combined Cycle and Riverton. As a result, Empire could incur higher fuel and purchased power costs than if the units were available for full commitment and dispatch.

Empire has also established a risk management practice of purchasing contracts for future fuel needs to meet underlying customer needs and manage cost and pricing uncertainty. Within this activity, Empire may incur losses from these contracts. By using physical and financial instruments, Empire is exposed to credit risk and market risk. Market risk is the exposure to a change in the value of commodities caused by fluctuations in market variables, such as price. The fair value of derivative financial instruments that Empire holds is adjusted cumulatively on a monthly basis until prescribed determination periods. At the end of each determination period, which is the last day of each calendar month in the period, any realized gain or loss for that period related to the contract will be reclassified to fuel expense and recovered or refunded to the customer through Empire's fuel adjustment mechanisms. Credit risk is the risk that the counterparty might fail to fulfill its obligations under contractual terms.

*Empire is subject to regulation in the jurisdictions in which it operates regulated utilities, including the rates that it can charge customers*

Empire is subject to comprehensive regulation by federal and state utility regulatory agencies, which significantly influences its operating environment and ability to recover costs from utility customers. The utility commissions in the states where Empire operates regulate many aspects of its utility operations, including the rates that Empire can charge customers, siting and construction of facilities, pipeline safety and compliance, customer service and Empire's ability to recover the costs that it incurs, including capital expenditures and fuel and purchased power costs.

The FERC has jurisdiction over wholesale rates for electric transmission service and electric energy sold in interstate commerce. Federal, state and local agencies also have jurisdiction over many of Empire's other activities.

Empire is also subject to prudency and similar reviews by regulators of costs that it incurs, including capital expenditures, fuel and purchased power costs and other operating costs.

Empire is unable to predict the impact of the regulatory activities of any of these agencies, including any regulatory disallowances that could result from prudency reviews, on its operating results. Despite Empire's requests, these regulatory commissions have sole discretion to leave rates unchanged, grant increases or order decreases in the base rates Empire charges its utility customers. They have similar authority with respect to Empire's recovery of increases in its fuel and purchased power costs. Rate proceedings through which Empire's prices and terms of service are determined typically involve numerous parties including customers, consumer advocates and governmental entities, some of whom take positions adverse to Empire. In addition, regulators' decisions may be appealed to the courts by Empire or other parties to the proceedings. These factors may lead to uncertainty and delays in implementing changes to Empire's prices or terms of service. If Empire's costs increase and Empire is unable to recover increased costs through base rates or fuel adjustment clauses, or if Empire is unable to fully recover its investments in new facilities, Empire's results of operations could be materially adversely affected. Changes in regulations or the imposition of additional regulations could also have a material adverse effect on Empire's results of operations.

In addition, although the current rate making process provides recovery of some future changes in rate base and operating costs, it does not reflect all changes in costs for the period in which new retail rates will be in place. This results in a lag (commonly referred to as "regulatory lag") between the time Empire incurs costs and the time when it can start recovering the costs through rates. This may result in under-recovery of costs, failure to earn the authorized return on investment, or both.

*Operations risks may adversely affect Empire's business and financial results*

The operation of Empire's regulated electric generation, and electric and gas transmission and distribution systems involves many risks, including breakdown or failure of expensive and sophisticated equipment, processes and personnel performance; inability to attract and retain management and other key personnel; workplace and public safety; operating limitations that may be imposed by workforce issues, equipment conditions, environmental or other regulatory requirements; fuel supply or fuel transportation reductions or interruptions; transmission scheduling constraints; unauthorized physical access to Empire's facilities; and catastrophic events such as fires, explosions, severe weather (including tornadoes and ice storms), acts of terrorism or other similar occurrences.

Empire has implemented training and preventive maintenance programs and has security systems and related protective infrastructure in place, but there is no assurance that these programs will prevent or minimize future breakdowns, outages or failures of Empire's generation facilities or related business processes. In those cases, Empire would need to either produce replacement power from its other facilities or purchase power from other suppliers at potentially volatile and higher cost in order to meet Empire's sales obligations, or implement emergency back-up business system processing procedures. In addition, certain catastrophic events can inflict extensive damage to Empire's equipment and facilities which can require Empire to incur additional operating and maintenance expense and additional capital expenditures. Empire's prices may not always be adjusted timely and adequately to reflect these higher costs.

These and other operating events and conditions may reduce Empire's revenues, increase costs, or both, and may materially affect its results of operations, financial position and cash flows.

*The regional power market in which Empire operates has changing market and transmission structures, which could have an adverse effect on Empire's results of operations, financial position and cash flows*

The Southwest Power Pool Regional Transmission Organization ("**SPP RTO**") is mandated by the FERC to ensure a reliable power supply, an adequate transmission infrastructure and competitive wholesale electricity prices. The SPP RTO functions as reliability coordinator, tariff administrator and regional scheduler for its member utilities, including Empire. Essentially, the SPP RTO independently operates Empire's transmission system as it interfaces and coordinates with the regional power grid. SPP RTO activities directly impact Empire's control of owned generating assets and the development and cost of transmission infrastructure projects within the SPP RTO region. The cost allocation methodology applied to these transmission infrastructure projects will increase Empire's operating expenses.

The SPP RTO implemented a Day-Ahead Market, or Integrated Marketplace ("**IM**"), in March 2014. The Southwest Power Pool Integrated Marketplace ("**SPP IM**") functions as a centralized dispatch, where Empire and other members submit offers to sell power and bids to purchase power. The SPP matches offers and bids to supply the next day generation needs of its members. It is expected that 90%-95% of all next day generation needed throughout the SPP territory will be cleared through this IM. This change could impact Empire's fuel costs, however, the net financial effect of these IM transactions will be processed through Empire's fuel adjustment mechanisms.

*Security breaches, criminal activity, terrorist attacks and other disruptions to Empire's information technology infrastructure could directly or indirectly interfere with Empire's operations, could expose Empire or Empire's customers or employees to a risk of loss, and could expose Empire to liability, regulatory penalties, reputational damage and other harm to Empire's business*

Empire relies upon information technology networks and systems to process, transmit and store electronic information, and to manage or support a variety of business processes and activities, including the generation, transmission and distribution of electricity, supply chain functions, and the invoicing and collection of payments from Empire's customers. Empire also use information technology systems to record, process and summarize financial information and results of operations for internal reporting purposes and to comply with financial reporting, legal and tax requirements. Empire's technology networks and systems collect and store sensitive data including system operating information, proprietary business information belonging to Empire and third parties, and personal information belonging to Empire's customers and employees.

Empire's information technology networks and infrastructure may be vulnerable to damage, disruptions or shutdowns due to attacks by hackers or breaches due to employee error or malfeasance, or other disruptions during software or hardware upgrades, telecommunication failures or natural disasters or other catastrophic events. The occurrence of any of these events could impact the reliability of Empire's generation, transmission and distribution systems; could expose Empire, Empire's customers or Empire's employees to a risk of loss or misuse of information, and could result in legal claims or proceedings, liability or regulatory penalties against Empire, damage Empire's reputation or otherwise harm Empire's business. Empire cannot accurately assess the probability that a security breach may occur, despite the measures that Empire takes to prevent such a breach, and Empire is unable to quantify the potential impact of such an event. Empire can provide no assurance that Empire will identify and remedy all security or system vulnerabilities or that unauthorized access or error will be identified and remedied.

Additionally, Empire cannot predict the impact that any future information technology or terrorist attack may have on the energy industry in general. Empire's facilities could be direct targets or indirect casualties of such attacks. The effects of such attacks could include disruption to Empire's generation, transmission and distribution systems or to the electrical grid in general, and could increase the cost of insurance coverage or result in a decline in the U.S. economy.

*Empire may be unable to recover increases in the cost of natural gas from Empire's natural gas utility customers, or may lose customers as a result of any price increase*

In Empire's regulated natural gas utility business, Empire is permitted to recover the cost of gas directly from Empire's customers through the use of a PGA provision. Empire's PGA provision is regularly reviewed by the MPSC. In addition to reviewing Empire's adjustments to customer rates, the MPSC reviews Empire's costs for prudency as well. To the extent the MPSC may determine certain costs were not incurred prudently, it could adversely affect Empire's gas segment earnings and cash flows. In addition, increases in natural gas costs affect total prices charged to Empire's customers and, therefore, the competitive position of gas relative to electricity and other forms of energy. Increases in natural gas costs may also result in lower usage by customers unable to switch to alternate fuels. Such disallowed costs or customer losses could have a material adverse effect on Empire's business, financial condition and results of operations.

*Any reduction in Empire's credit ratings could materially and adversely affect Empire's business, financial condition and results of operations*

The ratings indicate the agencies' assessment of Empire's ability to pay the interest and principal of these securities. A rating is not a recommendation to purchase, sell or hold securities and each rating should be evaluated independently of any other rating. The lower the rating, the higher the interest cost of the securities when they are sold. In addition, a downgrade in Empire's senior unsecured long-term debt rating would result in an increase in Empire's borrowing costs under its bank credit facility. If any of Empire's ratings fall below investment grade (investment grade is defined as Baa3 or above for Moody's and BBB- or above for S&P), Empire's ability to issue short-term debt, commercial paper or other securities or to market those securities would be impaired or made more difficult or expensive. Therefore, any such downgrades could have a material adverse effect on Empire's business, financial condition and results of operations. In addition, any actual downgrade of Empire's commercial paper rating from Moody's or Fitch may make it difficult for Empire to issue commercial paper. To the extent Empire is unable to issue commercial paper, Empire will need to meet its short-term debt needs through borrowings under its revolving credit facilities, which may result in higher costs.

No assurances can be provided that any of Empire's current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant.

*The cost and schedule of Empire's construction projects may materially change*

Empire's capital expenditures are material and include expenditures for environmental upgrades to Empire's existing facilities and additions to Empire's transmission and distribution systems, including costs to retire assets. There are risks that actual costs may be greater than expected, delays may occur in obtaining permits and materials, suppliers and contractors may not perform as required under their contracts, there may be inadequate availability, productivity or increased cost of qualified craft labour, start-up activities may take longer than planned, the scope and timing of projects may change, and other events beyond Empire's control may occur that may materially affect the schedule, budget, cost and performance of projects. To the extent the completion of projects is delayed, Empire expects that the timing of receipt of increases in base rates reflecting Empire's investment in such projects will be correspondingly delayed. Costs associated with these projects will also be subject to prudency review by regulators as part of future rate case filings and recovery of all costs may not be allowed.

*Financial market disruptions may increase financing costs, limit access to the credit markets or cause reductions in investment values in Empire's pension plan assets*

Although Empire believes it is unlikely it will have difficulty accessing the markets for the capital needed for future capital expenditures (if such a need arises), financing costs could fluctuate. Financial market disruptions and volatility in discount rates could lead to increased funding obligations due to reduced asset values and increased benefit obligations. Empire's funding policy is to contribute annually an amount at least equal to the actuarial cost of post-retirement benefits. The actual minimum pension funding requirements are determined based on the results of the actuarial valuations and the performance of Empire's pension assets during the current year. Future market changes could result in increased pension and OPEB liabilities and funding obligations.

*Failure to attract and retain an appropriately qualified workforce could adversely affect Empire's business, financial condition and results of operations*

Certain events, such as an aging workforce, mismatch of skill set or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge base and the lengthy time required for skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to new employees, or future availability and cost of contract labour may adversely affect the ability to manage and operate the business. If Empire is unable to successfully attract and retain an appropriately qualified workforce, Empire's business, financial condition and results of operations could be adversely affected.

*Empire is subject to adverse publicity and reputational risks, which makes Empire vulnerable to negative customer perception and increased regulatory oversight or other sanctions*

Like other utility companies, Empire has a large consumer customer base and, as a result, is subject to public criticism focused on the reliability of Empire's distribution services and the speed with which Empire is able to respond to outages caused by storm damage or other unanticipated events. Adverse publicity of this nature may render legislatures, public utility commissions and other regulatory authorities and government officials, less likely to view public utility companies in a favorable light, and may cause Empire to be susceptible to less favorable legislative and regulatory outcomes or increased regulatory oversight. Unfavorable regulatory outcomes can include more stringent laws and regulations governing Empire's operations, such as reliability and customer service quality standards or vegetation management requirements, as well as fines, penalties or other sanctions or requirements. The imposition of any of the foregoing could have a material adverse effect on Empire's business, financial condition and results of operations.

*Empire's businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations*

Empire's businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities are particularly sensitive to variations in weather conditions. Those utilities forecast energy sales on the basis of normal weather, which represents a long-term historical average. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

# 5. DIVIDENDS

*Common Shares*

The total amount of dividends declared on the Common Shares for fiscal 2013, 2014 and 2015 were $68.3 million, $83.1 million, and $124.8 million respectively. The amount of dividends declared for each Common Share of APUC for fiscal 2013, 2014 and 2015 were $0.33, $0.37, and $0.49 respectively.

APUC follows a quarterly dividend schedule, subject to subsequent Board declarations each quarter. Effective May 7, 2015, the Board approved a dividend increase from CDN $0.35 to U.S. $0.385, paid quarterly at a rate of U.S. $0.09625 per Common Share. The change in the currency of the dividend better aligns APUC's dividend with the currency profile of its underlying operations. APUC's consolidated assets are approximately 82% based in the U.S. and generate approximately 77% of its underlying cash flows.

The Board has adopted a dividend policy to provide sustainable dividends to shareholders, considering cash flow from operations, financial condition, financial leverage, working capital requirements and investment opportunities. The Board can modify the dividend policy from time to time at its discretion. There are no restrictions on the dividend policy of APUC. The amount of dividends declared and paid is ultimately dependent on a number of factors, including the risk factors previously noted. See "Enterprise Risk Management".

*Preferred Shares*

On November 9, 2012, APUC issued 4,800,000 Series A Shares (the "Series A Shares"). For an initial six year period the holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.1250 per Series A Share. In each of 2013, 2014 and 2015, dividends paid to Series A Share holders totalled $5.4 million per year.

On January 1, 2013, the Corporation issued 100 redeemable Series C Shares and exchanged such shares for the 100 Class B units of St. Leon LP, including 36 units held indirectly by the Senior Management. The Series C Shares provide dividends essentially identical to that expected from the Class B units. In each of 2013, 2014 and 2015, dividends paid to Series C preferred shareholders were $0.9 million.

On March 5, 2014, APUC issued 4,000,000 Series D Shares. For an initial five year period the holders of Series D Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board, payable quarterly on the last business day of March, June, September and December in each year at an annual rate equal to $1.250 per Series D Share. In 2014, and 2015, dividends paid to Series D Shareholders totalled $4.1 million and $5.0 million.

## 5.1 Dividend Reinvestment Plan

Effective October 1, 2011, APUC introduced a shareholder dividend reinvestment plan (the "**Reinvestment Plan**") which is offered to registered holders of Common Shares.

The purpose of the Reinvestment Plan is to enable Shareholders to invest cash dividends paid on Common Shares in additional Common Shares ("**Plan Shares**"). All such Plan Shares will be, at APUC's election, either (i) Common Shares purchased on the open market through the facilities of the TSX ("**Market Purchase**") or (ii) newly issued Common Shares purchased from treasury ("**Treasury Purchase**").

The price at which Plan Shares will be purchased with such cash dividends will be (i) in the case of a Market Purchase, the volume weighted average price paid (excluding brokerage commissions, fees and transaction costs) per Plan Share by the agent for all Plan Shares purchased in respect of a dividend payment date under the Reinvestment Plan, or (ii) in the case of a Treasury Purchase, the volume weighted average of the trading price for Common Shares on the TSX for the five trading days immediately preceding the relevant dividend payment date less a discount, if any, of up to five percent (5%), at APUC's election. No commissions, service charges or brokerage fees are payable by shareholders in connection with the Reinvestment Plan.

As at December 31, 2015, 24,036,115 Common Shares had been registered with the Reinvestment Plan.

# 6. DESCRIPTION OF CAPITAL STRUCTURE

## 6.1 Common Shares

The Common Shares are publicly traded on the TSX. As at December 31, 2015, APUC had 255,869,419 issued and outstanding Common Shares.

APUC may issue an unlimited number of Common Shares. The holders of Common Shares are entitled to dividends, if and when declared; to one vote for each share at meetings of the holders of Common Shares; and to receive a pro rata share of any remaining property and assets of APUC upon liquidation, dissolution or winding up of APUC. All shares are of the same class and with equal rights and privileges and are not subject to future calls or assessments.

## 6.2 Private Placements of Subscription Receipts and Common Shares to Emera

As at March 10, 2016, in total, Emera owns 50,126,766 Common Shares representing approximately 19.6% of the total outstanding Common Shares of the Corporation, and there are 12,024,753 Subscription Receipts currently held by Emera. APUC believes the issuance of shares to Emera is an efficient way to raise equity as it avoids underwriting fees, legal expenses and other costs associated with raising equity in the capital markets.

*Subscription Receipts*

On October 7, 2014, the Corporation issued 8,708,170 Subscription Receipts at a purchase price of $8.90 per Subscription Receipt for an aggregate subscription price of $77.5 million. The investment was made under the strategic investment agreement (the "**Strategic Investment Agreement**") entered into between Emera and APUC on April 29, 2011, in support of the acquisition by APUC of the Odell Wind Project in Minnesota (the "**Odell Acquisition**"). As at November 14, 2015 (the first anniversary of the closing of the Odell Acquisition), the Subscription Receipts were convertible to Common Shares on a one-for-one basis, subject to adjustments as provided in the applicable subscription agreement. On October 7, 2016, the Subscription Receipts will automatically convert into Common Shares, if Emera has not yet exercised its option to convert.

On December 29, 2014, the Corporation issued 3,316,583 Subscription Receipts at a purchase price of $9.95 per Subscription Receipt for an aggregate subscription price of $33.0 million. The investment was made under the Strategic Investment Agreement, in support of the acquisition by APUC of Park Water in Montana and California (the "**Park Water Acquisition**"). The proceeds of the subscription have been used by APUC to partially finance the Park Water Acquisition. As at December 29, 2015 (the first anniversary of the closing of the subscription transaction), the Subscription Receipts were convertible to Common Shares of APUC on a one-for-one basis, subject to adjustments as provided in the applicable subscription agreement. On December 29, 2016, the Subscription Receipts will automatically convert into Common Shares, if Emera has not yet exercised its option to convert.

Conversion of the aforementioned Subscription Receipts into Common Shares is conditional on Emera's holdings not exceeding 25% of the outstanding Common Shares at the time of conversion.

*Common Shares*

For the year ended December 31, 2015, APUC did not issue any Common Shares to Emera.

For the year ended December 31, 2014, APUC did not issue any Common Shares to Emera.

For the year ended December 31, 2013, APUC issued a total of 15,223,016 Common Shares for proceeds of $90.5 million pursuant to the conversion of Subscription Receipts issued to Emera in contemplation of certain previously announced transactions, as outlined below:

- In connection with the closing of the acquisition of the Minonk and Senate Wind Facilities that occurred on December 10, 2012, on February 7, 2013, APUC issued 2,614,005 Common Shares upon the conversion of Subscription Receipts that were issued at a price of $5.74 per subscription receipt. Additionally, on February 14, 2013, APUC issued 5,228,011 Common Shares upon the conversion of Subscription Receipts that were issued at a price of $5.74 per Subscription Receipt . The total $45.0 million in cash proceeds were used to fund a portion of the cost of the acquisition;
- On December 21, 2012, in connection with the acquisition of Emera's non-controlling interest in CalPeco Electric System, APUC received $38.7 million from Emera related to the issuance of 8,211,000 Subscription Receipts which were issued at a price of $4.72 per Subscription Receipt . On February 14, 2013, APUC issued 3,421,000 Common Shares upon partial conversion of these Subscription Receipts ; and
- On March 26, 2013, in connection with the acquisition of the Peach State Gas System, APUC issued 3,960,000 Common Shares at a price of $7.40 per share to Emera for total proceeds of approximately $29.3 million.

## 6.3 Preferred Shares

APUC is also authorized to issue an unlimited number of preferred shares, issuable in one or more series, containing terms and conditions as approved by the Board. As at December 31, 2015, APUC had outstanding:

- 4,800,000 cumulative rate reset Series A Shares, yielding 4.5% annually for the initial six-year period ending on December 31, 2018;
- 100 Series C preferred shares that were issued in exchange for 100 Class B limited partnership units by St. Leon; and
- 4,000,000 cumulative rate reset Series D Shares, yielding 5.0% annually for the initial five-year period ending on March 31, 2019.

On November 9, 2012, APUC issued 4.8 million Series A Shares at a price of $25 per share, for aggregate gross proceeds of $120 million. The Series A Shares yield 4.5% per cent annually for the initial six-year period ending on December 31, 2018. The Series A Shares have been assigned a rating of P-3 and Pfd-3(low) by S&P and DBRS respectively. The proceeds of the offering were used primarily to partially fund the acquisition of the U.S Wind Portfolio interests which closed on December 10, 2012. The Series A Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series B (the "**Series B Shares**").

On January 1, 2013, APUC issued an aggregate of 100 Series C Shares to the holders of the Class B units of St. Leon LP, in exchange for such Class B units. (See "Description of the Business – Business Associations with APMI and Senior Executives - St Leon LP Units".)

On March 5, 2014, APUC issued 4.0 million Series D Shares at a price of $25 per share, for aggregate gross proceeds of $100 million. The Series D Shares yield 5.0% annually for the initial five-year period ending March 31, 2019. The preferred shares have been assigned a rating of P-3 (High) and Pfd-3 (Low) by S&P and DBRS respectively. The net proceeds of the offering were used to partially finance certain of APUC's previously disclosed growth opportunities, reduce amounts outstanding on APUC's credit facilities and for general corporate purposes. The Series D Shares are convertible in certain circumstances into cumulative floating rate preferred shares, Series E (the "**Series E Shares**").

Subject to applicable corporate law, the outstanding preferred shares are non-voting and not entitled to receive notice of any meeting of shareholders, except that the Series A Shares and Series D Shares (and the Series B Shares and Series E Shares, respectively, into which they are convertible) will be entitled to one vote per share if the Corporation shall have failed to pay eight quarterly dividends on such shares. The terms of the outstanding preferred shares do not contain a right to participate in a take-over bid of the Common Shares of the Corporation.

As at December 31, 2015, APUC had 4.8 million Series A Shares, 100 Series C Shares, and 4.0 million Series D Shares outstanding.

## 6.4 Convertible Debentures

### 6.4.1 Series 3 Debentures

On December 2, 2009, APUC issued $63,250,000 principal amount of Series 3 Debentures.

On November 19, 2012, APUC announced its intent to redeem on January 1, 2013 all of the outstanding Series 3 Debentures at such date. During the year ended December 31, 2012, a principal amount of $61.6 million Series 3 Debentures were converted into 14,669,266 Common Shares. The Series 3 Debentures were convertible into Common Shares at the option of the holder at a conversion price of $4.20 per Common Share. On December 31, 2012, there was $0.96 million principal amount of Series 3 Debentures outstanding. On January 1, 2013, APUC redeemed the outstanding Series 3 Debentures and issued 150,816 Common Shares as a result of the redemption. Following the redemption, there were no Series 3 Debentures outstanding.

### 6.4.2 Convertible Unsecured Subordinated Debentures

On February 9, 2016, in connection with the acquisition of Empire, the Corporation completed the sale of $1.0 billion aggregate principal amount of 5.0% convertible unsecured subordinated debentures. The Debentures will trade on the TSX under the ticker symbol "AQN.IR". The Debentures were sold on an installment basis at a price of $1,000 dollars per Debenture, of which $333 dollars was paid on closing of the Debenture Offering and the remaining $667 dollars (the "Final Installment") is payable on a date ("Final Installment Date") to be fixed following satisfaction of conditions precedent to the closing of the acquisition of Empire. On March 9, 2016, the Underwriters exercised their option to acquire an additional $150.0 million of Debentures bringing the total Debentures issued under the Installment Debenture Offering to $1.15 billion.

The Debentures will mature on March 31, 2026 and bear interest at an annual rate of 5% per $1,000 dollars principal amount of Debentures until and including the Final Instalment Date, after which the interest rate will be 0%. Based on the First Installment of $333 dollars per $1,000 dollars principal amount of Debentures, the effective annual yield to and including the Final Installment Date is 15%, and the effective annual yield thereafter is 0%.

If the Final Installment Date occurs on a day that is prior to the first anniversary of the closing of the Offering, holders of Debentures who have paid the Final Instalment on or before the Final Installment Date will be entitled to receive, on the business day following the Final Installment Date, in addition to the payment of accrued and unpaid interest to and including the Final Installment Date, an amount equal to the interest that would have accrued from the day following the Final Installment Date to and including the first anniversary of the closing of the Offering had the Debentures remained outstanding and continued to accrue interest until and including such date (the "**Make-Whole Payment**"). No Make-Whole Payment will be payable if the Final Installment Date occurs on or after the first anniversary of the closing of the Offering. Prior to the closing of the Acquisition, the Corporation will at all times have cash on hand or maintain readily available capacity under the revolving credit facilities of not less than the aggregate amount of the First Instalment paid on the closing of the Offering and the exercise of the over-allotment option.

At the option of the holders and provided that payment of the Final Installment has been made, each Debenture will be convertible into Common Shares of the Company at any time after the Final Installment Date, but prior to the earlier of maturity or redemption by the Corporation, at a conversion price of $10.60 per Common Share.

Prior to the Final Instalment Date, the Debentures may not be redeemed by the Corporation, except that Debentures will be redeemed by the Corporation at a price equal to their principal amount plus accrued and unpaid interest following the earlier of: (i) notification to holders that the conditions necessary to approve the acquisition of Empire will not be satisfied; (ii) termination of the acquisition agreement; and (iii) September 11, 2017 if notice of the Final Instalment Date has not been given to holders on or before September 8, 2017. Upon any such redemption, the Corporation will pay for each Debenture $333 dollars plus accrued and unpaid interest to the holder of the Instalment Receipt. In addition, after the Final Installment Date, any Debentures not converted may be redeemed by the Corporation at a price equal to their principal amount plus any unpaid interest, which accrued prior to and including the Final Instalment Date.

At maturity, the Corporation will have the right to pay the principal amount due in cash or in Common Shares. In the case of Common Shares, such shares will be valued at 95% of their weighted average trading price on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the maturity date.

## 6.5 Employee Share Purchase Plan

APUC has an Employee Share Purchase Plan (the "**ESPP**") which allows eligible employees to use a portion of their earnings to purchase Common Shares. For employees resident in Canada, APUC will match up to 20% of an employee's contribution amount for the first $5,000 contributed annually and 10% of an employee's contribution amount for contributions over $5,000 and up to $10,000 annually. For employees resident in the United States, APUC will match 15% of an employee's contribution amount up to $10,000 annually. Shares purchased through the APUC matched portion vest over a one year period. At APUC's option, the shares may be (i) issued to participants from treasury at the weighted average share price at the time of issue or

(ii) acquired on behalf of participants by purchases through the facilities of the TSX by an independent broker. The aggregate number of shares reserved for issuance from treasury by APUC under this plan shall not exceed 2,000,000 shares. During the year, the Corporation issued 111,355 Common Shares to employees under the ESPP plan.

As at December 31, 2015, a total of 351,766 shares had been issued under the ESPP.

## 6.6 Directors Deferred Share Units

APUC has a deferred share unit plan. Under the plan, non-employee directors of APUC may elect annually to receive all or any portion of their compensation in deferred share units ("**DSUs**") in lieu of cash compensation. Directors' fees are paid on a quarterly basis and at the time of each payment of fees, the applicable amount is converted to DSUs. A DSU has a value equal to one of the Corporation's Common Share. Dividends accumulate in the DSU account and are converted to DSUs based on the market value of the shares on that date. DSUs cannot be redeemed until the Director retires, resigns, or otherwise leaves the Board. The DSUs provide for settlement in cash or shares at the election of APUC. As APUC does not expect to settle the DSU's in cash, these DSUs are accounted for as equity awards.

During the year, the Corporation issued 47,230 DSUs to the directors of the Corporation. As at December 31, 2015, a total of 157,471 DSUs had been granted under the DSU plan.

## 6.7 Performance Share Units

APUC issues performance share units ("**PSUs**") to certain members of management other than senior executives as part of APUC's long-term incentive program. The PSUs have a three year vesting period, after which the number of shares vested can range from 0% to 197.5% of the number of PSUs granted. Dividends accumulate during vesting periods are converted to PSUs based on the market value of the shares on that date. None of the PSUs have voting rights. Any PSUs not vested at the end of a performance period will expire.

The plan provides for settlement in cash or shares at the election of the Corporation. At the annual general meeting held on June 18, 2014, the shareholders approved a maximum of 500,000 shares issuable from Treasury to settle PSUs. With the ability to issue shares from Treasury or purchase shares on the market, the Corporation expects to settle the remaining PSUs in shares. As a result, the PSUs continue to be accounted for as equity awards. Compensation expense associated with PSUs is recognized rateably over the performance period based on APUC's estimated achievement of the established metrics. Compensation expense for awards with performance conditions will only be recognized for those awards for which it is probable that the performance conditions will be achieved and which are expected to vest. The compensation expense will be estimated based upon an assessment of the probability that the performance metrics will be achieved and anticipated vesting percentage.

During the year, the Corporation settled 41,131 vested PSUs and issued 212,250 PSUs to executives and employees of the Corporation. As at December 31, 2015, a total of 564,116 PSU's have been granted and outstanding under the PSU plan.

## 6.8 Shareholders' Rights Plan

The shareholders' rights plan (the "**Rights Plan**") is designed to ensure the fair treatment of shareholders in any transaction involving a potential change of control of APUC and will provide the Board and shareholders with adequate time to evaluate any unsolicited take-over bid and, if appropriate, to seek out alternatives to maximize shareholder value. An amended and restated rights plan (the "**Amended and Restated Rights Plan**") was approved by shareholders at the annual and special meeting of shareholders of APUC held in 2013.

Until the occurrence of certain specific events, the rights will trade with the Common Shares and be represented by certificates representing the Common Shares. The rights become exercisable only when a person, including any party related to it or acting jointly with it, with the exception of Emera, acquires or announces its intention to acquire twenty percent or more of the outstanding Common Shares without complying with the permitted bid provisions of the Plan. The application of the Rights Plan to acquisition of Common Shares by Emera under allowed transactions was waived following shareholder approval at the annual and special meeting of shareholders held on June 21, 2010. Should a non-permitted bid be launched, each right would entitle each holder of shares (other than the acquiring person and persons related to it or acting jointly with it) to purchase additional Common Shares at a fifty percent discount to the market price at the time.

It is not the intention of the Rights Plan to prevent take-over bids but to ensure their proper evaluation by the market. Under the Rights Plan, a permitted bid is a bid made to all shareholders for all of their Common Shares on identical terms and conditions that is open for no less than 60 days. If at the end of 60 days at least fifty percent of the outstanding Common Shares, other than those owned by the offeror and certain related parties, have been tendered and not withdrawn, the offeror may take up and pay for the Common Shares but must extend the bid for a further ten days to allow all other shareholders to tender.

At the annual and special shareholders' meeting held on April 23, 2013, the shareholders of APUC approved an amendment to and the continuance of the Rights Plan. In the Amended and Restated Rights Plan, the definition of "Exempt Acquisition" has been amended to provide that, in determining whether Emera has become a beneficial owner of more than 25% of the

Common Shares outstanding as a result of certain issuances of Common Shares or convertible securities by the Corporation (including a distribution of Common Shares or convertible securities by way of private placement), the Common Shares to be issued to Emera shall be included in the aggregate number of outstanding Common Shares. If, under such determination, Emera becomes the beneficial owner of not more than 25% of the outstanding Common Shares as a result of an Exempt Acquisition, Emera is not considered an "Acquiring Person" for purposes of the Amended and Restated Rights Plan. The Amended and Restated Rights Plan otherwise provides that the Common Shares to be issued to a person (other than Emera) under an Exempt Acquisition are not to be included in the outstanding Common Shares in determining whether such person becomes the beneficial owner of more than 25% of the outstanding Common Shares.

The Amended and Restated Rights Plan will remain in effect until the termination of the annual meeting of the shareholders of APUC in 2016 or its termination under the terms of the of Amended and Restated Rights Plan. The Amended and Restated Rights Plan is similar to rights plans adopted by many other Canadian corporations.

## 6.9 Stock Option Plan

The Corporation implemented a stock option plan (the "**Stock Option Plan**") in 2010. The purpose of the Stock Option Plan is to attract, retain and motivate persons as key service providers to the Corporation and its affiliates and to advance the interests of the Corporation by providing such persons with the opportunity, through stock options ("**Options**"), to acquire a proprietary interest in the Corporation.

The Stock Option Plan authorizes the Board to issue Options to directors, officers or employees of the Corporation or any affiliate (an "**Eligible Individual**"), a corporation controlled by an Eligible Individual or any person/company, partnership, trust or corporation engaged to provide management or consulting services for the Corporation or any affiliate ("**Eligible Persons**").

The aggregate number of Common Shares that may be reserved for issuance under the Stock Option Plan must not exceed 10% of the number of Common Shares outstanding at the time the Options are granted. For greater clarity, the Stock Option Plan is "reloading" in the sense that, to the extent that Options expire or are terminated, cancelled or exercised, the Corporation may make a further grant of Options in replacement for such expired, terminated, cancelled or exercised Options, provided that the 10% maximum is not exceeded. No fractional Common Shares may be purchased or issued under the Stock Option Plan.

In addition, under the Stock Option Plan:

- subject to the terms of the Stock Option Plan, the number of Common Shares subject to each Option, the exercise price of each Option, the expiration date of each Option, the extent to which each Option vests and is exercisable from time to time during the term of the Option and other terms and conditions relating to each Option will be determined by the Board from time to time;
- subject to any adjustments pursuant to the provisions of the Stock Option Plan, the exercise price of any Option shall in no circumstances be lower than the Market Price (as defined below) of the Common Shares on the date on which the Board approves the grant of the Option;
- Options will be personal to the grantee and will be non-transferable and non-assignable, except in certain limited circumstances;
- the maximum number of Common Shares which may be reserved for issuance to insiders under the Stock Option Plan, together with the number of Common Shares reserved for issuance to insiders under any other securities based compensation arrangement, shall be 10% of the Common Shares outstanding at the time of the grant;
- the maximum number of Common Shares which may be issued to insiders under the Stock Option Plan and all other security based compensation arrangements within a one year period shall be 10% of the Common Shares outstanding at the time of the issuance;
- non-employee director participation in the Stock Option Plan is limited to the lesser of (i) a reserve of 1% of the Common Shares outstanding for non-employee directors as a group and (ii) an annual equity award value of $100,000 per director;
- if the expiration date for an Option occurs during a Blackout Period (as defined below) or within 10 business days after the expiry date of a Blackout Period applicable to a person granted Options (an "**Optionee**"), then the expiration date for that option will be extended to the 10th business day after the expiry date of the Blackout Period. A "**Blackout Period**" is a period of time of time during which the Optionee cannot exercise an Option, or sell Common Shares issuable pursuant to the exercise of Options, due to applicable policies of the Corporation in respect of insider trading); and
- except in certain circumstances, the term of an Option shall not exceed ten (10) years from the date of the grant of the Option.

Under the Stock Option Plan, "**Market Price**" of the Common Shares is defined as the volume weighted average trading price of such Common Shares on the TSX (or, if such Common Shares are not then listed and posted for trading on the TSX, on such stock exchange in Canada on which such Common Shares are listed and posted for trading as may be selected for such purpose by the Board) for the five consecutive trading days immediately preceding such date, provided that in the event that such Common Shares did not trade on any of such trading days, the Market Price will be the average of the bid and ask prices in respect of such Common Shares at the close of trading on all of such trading days and provided that in the event that such Common Shares are not listed and posted for trading on any stock exchange, the Market Price will be the fair market value of such Common Shares as determined by the Board in its sole discretion.

The Stock Option Plan provides that, except as set out in the Stock Option Plan or any resolution passed at any time by the Board or the terms of any option agreement or employment agreement with respect to any Option or an Optionee, an Option and all rights to purchase Common Shares pursuant thereto shall expire and terminate immediately upon the Optionee who holds such Option ceasing to be an Eligible Person.

Where an Optionee (other than a service provider) resigns from the Corporation or is terminated by the Corporation for cause, the Optionee's unvested Options shall immediately be forfeited and the Optionee's vested Options may be exercised for a period of 30 days after the date of resignation or termination.

Where an Optionee (other than a service provider) retires from the Corporation or ceases to serve the Corporation or an affiliate as a director, officer or employee for any reason other than a termination by the Corporation for cause, the Optionee's unvested Options may be exercised within 90 days after such retirement or termination. The Board may in such circumstances accelerate the vesting of unvested Options then held by the Optionee at the Board's discretion.

In the event that an Optionee, other than a service provider, has suffered a permanent disability, Options previously granted to such Optionee shall continue to vest and be exercisable in accordance with the terms of the grant and the provisions of the Stock Option Plan, but no additional grants of Options may be made to the Optionee.

If an Optionee, other than a service provider, dies, all unexercised Options held by such Optionee at the time of death immediately vest, and such Optionee's personal representatives or heirs may exercise all Options within one year after the date of such death.

All Options granted to service providers shall terminate in accordance with the terms, conditions and provisions of the associated option agreement between the Corporation and such service providers, provided that such termination shall occur no later than the earlier of (i) the original expiry date of the term of the Option and (ii) one year following the date of termination of the engagement of the service provider.

Options may be exercised in accordance with the specific terms of their grant and by the Optionee delivering the exercise price to the Corporation for all of the Options exercised. The Optionee may also surrender Options and receive in exchange for each such Option, the amount by which the Market Price of the Common Shares exceeds the exercise price of the Option (the "**In-the-Money Amount**"). If the Optionee elects to surrender any Options in exchange for the In-the-Money Amount, the Corporation will determine whether to pay such amount in cash or in Common Shares representing the equivalent of the In-the-Money Amount based on the Market Price of the Common Shares at the date of exercise, in each case net of an amount equal to any withholding taxes.

In the event that the Common Shares are at any time changed or affected as a result of the declaration of a stock dividend, a Common Share subdivision or consolidation, the number of Common Shares reserved for Options shall be adjusted accordingly by the Board to such extent as it deems proper in its discretion.

If, after the grant of an Option and prior to its expiry:

(i) the Common Shares are reclassified, reorganized or otherwise changed (a "**Share Reorganization**"), otherwise than as specified in the immediately preceding paragraph, or

(ii) subject to the Corporation's right to allow the exercise of vested and unvested Options following the occurrence of certain transactions, the Corporation shall consolidate, merge or amalgamate with or into another corporation (a "**Merger**", with the resulting corporation being the "**Successor Corporation**"),

the Optionee will receive, upon the subsequent exercise of his or her Options in accordance with the Stock Option Plan, the number of Common Shares or securities of the appropriate class of the Corporation or Successor Corporation, as the case may be, that the Optionee would have received if on the record date of such Share Reorganization or Merger the Optionee were the registered holder of the number of Common Shares to which the Optionee was prior thereto entitled to receive on exercise of his or her Options.

The Board may amend, suspend or discontinue the Stock Option Plan or amend Options granted under the Stock Option Plan at any time without shareholder approval; provided, however, that:

(a) approval by a majority of the votes cast by shareholders present and voting in person or by proxy at a meeting of shareholders of the Corporation shall be obtained for the following amendments:

(i) any amendment for which, under the requirements of the TSX or any applicable law, shareholder approval is required;

(ii) reduction of the exercise price, or cancellation and reissuance of Options or other entitlements, of non-insider Options granted under the Stock Option Plan;

(iii) extension of the term of Options beyond the original expiry date of non-insider Options;

(iv) change in Eligible Participants that may permit an increase to the limit imposed on non-employee director participation;

(v) permitting of Options granted under the Stock Option Plan to be transferable or assignable other than for estate settlement purposes; or

(vi) amendment to the Stock Option Plan's amendment provisions; and

(b) the consent of the Optionee is obtained for any amendment which alters or impairs any Option previously granted to an Optionee under the Stock Option Plan.

Notwithstanding the other provisions of the Stock Option Plan, if:

(a) the Corporation proposes to amalgamate, merge or consolidate with any other corporation (other than a wholly-owned affiliate) or to liquidate, dissolve or wind-up;

(b) an offer to purchase or repurchase all of the Common Shares shall be made to all holders of Common Shares which offer has been approved or accepted by the Board; or

(c) the Corporation proposes the sale of all or substantially all of the assets of the Corporation as an entirety, or substantially as an entirety, so that the Corporation shall cease to operate any active business,

then, the Corporation will have the right, upon written notice thereof to Optionees, to permit the exercise of all such Options, whether or not vested, within the 20 day period next following the date of such notice and to determine that upon the expiration of such 20 day period, all rights of the Optionee to such Options or to exercise same (to the extent not theretofore exercised) shall *ipso facto* terminate and cease to have further force or effect whatsoever.

During the year, the Corporation issued 1,627,525 Options to employees of the Corporation.

As at December 31, 2015, a total of 7,164,652 Options had been issued and outstanding under the plan, which is 2.8% of the total outstanding Common Shares of the Corporation. The number of Common Shares that have been issued pursuant to the Stock Option Plan is nil.

# 7. MARKET FOR SECURITIES

## 7.1 Trading Price and Volume

### 7.1.1 Common Shares

APUC's Common Shares are listed and posted for trading on the TSX under the symbol "AQN". The following table sets forth the high and low closing prices and the aggregate volume of trading of the Common Shares for the periods indicated (as quoted by the TSX).

| 2015 | High ($) | Low ($) | Volume (000's) |
|---|---|---|---|
| January | 10.44 | 9.41 | 10,801,887 |
| February | 10.51 | 9.97 | 6,615,320 |
| March | 10.39 | 7.50 | 25,103,508 |
| April | 10.10 | 9.21 | 11,608,674 |
| May | 9.94 | 9.43 | 12,760,881 |
| June | 9.80 | 8.87 | 9,520,132 |
| July | 9.77 | 9.05 | 8,805,825 |
| August | 9.99 | 8.59 | 9,723,253 |
| September | 9.84 | 9.09 | 7,620,206 |
| October | 10.30 | 9.20 | 13,507,930 |
| November | 10.94 | 10.03 | 12,404,511 |
| December | 11.35 | 10.09 | 13,973,388 |

### 7.1.2 Preferred Shares

*Series A Shares*

APUC's Series A Shares became listed and commenced trading under the symbol "AQN.PR.A" on November 9, 2012.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series A Shares for the periods indicated (as quoted by the TSX).

| 2015 | High ($) | Low ($) | Volume (000's) |
|---|---|---|---|
| January | 25.80 | 22.42 | 58,012 |
| February | 22.98 | 21.78 | 40,754 |
| March | 22.15 | 20.15 | 112,428 |
| April | 21.90 | 20.19 | 107,962 |
| May | 22.08 | 21.31 | 35,485 |
| June | 21.86 | 19.40 | 58,131 |
| July | 20.18 | 17.99 | 92,850 |
| August | 19.37 | 17.35 | 59,071 |
| September | 18.52 | 16.02 | 111,196 |
| October | 19.95 | 16.14 | 62,171 |
| November | 19.70 | 17.75 | 156,176 |
| December | 18.60 | 16.00 | 102,185 |

*Series D Shares*

APUC's Series D Shares became listed and commenced trading under the symbol "AQN.PR.D" on March 5, 2014.

The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series D Shares for the periods indicated (as quoted by the TSX).

| 2015 | High ($) | Low ($) | Volume (000's) |
|---|---|---|---|
| January | 26.49 | 24.81 | 140,320 |
| February | 25.49 | 24.49 | 59,039 |
| March | 25.41 | 22.40 | 65,637 |
| April | 25.04 | 22.62 | 108,963 |
| May | 25.00 | 24.27 | 110,908 |
| June | 25.00 | 23.24 | 67,211 |
| July | 24.33 | 22.44 | 72,365 |
| August | 23.37 | 19.86 | 49,463 |
| September | 21.51 | 18.75 | 43,439 |
| October | 22.44 | 17.95 | 78,993 |
| November | 22.85 | 20.02 | 76,495 |
| December | 21.69 | 17.83 | 154,600 |

## 7.2 Prior Sales

During the year ended December 31, 2010, 1,160,205 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $4.05 per share. One-third of the Options vested on each of January 1, 2011, 2012 and 2013.

During the year ended December 31, 2011, the Board approved the following grant of Options:

- On March 22, 2011, 892,107 Options were granted to senior executives of APUC which allow for the purchase of Common Shares at a price of $5.23 per share;
- On June 21, 2011, 171,642 Options were granted to a senior executive of APCo which allow for the purchase of Common Shares at a price of $5.64 per share;

- On July 28, 2011, 90,909 Options were granted to a senior executive of APUC which allow for the purchase of Common Shares at a price of $5.74 per share; and
- On September 13, 2011, 172,242 Options were granted to a senior executive of Liberty Utilities which allow for the purchase of Common Shares at a price of $5.65 per share.

In each case, one-third of the Options vested on each of January 1, 2012, 2013, and 2014.

On March 14, 2012, 1,194,606 Optionswere granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.22 per share. One-third of the Options vest on each of January 1, 2013, 2014 and 2015.

On June 19, 2012, 69,016 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $6.56 per share. One-third of the Options vest on each of January 1, 2013, 2014 and 2015.

On March 14, 2013, 816,402 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.72 per share. One-third of the Options vest on each of January 1, 2014, 2015, and 2016.

On May 13, 2014, 969,998 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $7.95 per share. One-third of the Options vest on each of January 1, 2015, 2016, and 2017.

On May 19, 2015, 1,608,974 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.76 per share. On August 27, 2015, 18,551 Options were granted to senior executives of APUC and senior managers which allow for the purchase of Common Shares at a price of $9.23 per share. One-third of the Options vest on each of January 1, 2016, 2017, and 2018.

All Options were issued using the five day volume weighted average price of the underlying Common Shares at the date of the grant. In all cases, Options may be exercised up to eight years following the date of grant. As at December 31, 2015, APUC had 7,164,652 options issued and outstanding. As at December 31, 2015, 4,618,323 options were exercisable. No Options were exercised in 2015, 2014 or 2013.

| | Number of shares | Weighted average exercise price | Weighted average remaining contractual term |
|---|---|---|---|
| Balance at December 31, 2014 | 5,537,127 | $6.09 | 4.96 |
| Granted | 1,627,525 | $9.75 | 8.00 |
| Balance at December 31, 2015 | 7,164,652 | $6.92 | 4.74 |
| Exercisable at December 31, 2015 | 4,618,323 | $5.74 | 3.55 |

In addition, APUC issued Common Shares to Emera upon the conversion of Subscription Receipts in 2012 and 2013 and issued Common Shares to Emera upon a private placement in March 2013 as described under "*Description of Capital Structure – Private Placements of Subscription Receipts and Common Shares to Emera*".

## 7.3 Escrowed Securities and Securities Subject to Contractual Restrictions on Transfer

The following securities of APUC are subject to contractual restrictions on transfer as of the date of this AIF:

| Description | Number of Securities subject to contractual restrictions | Percentage of class |
|---|---|---|
| Common Shares | 50,126,766 | 19.6% |

Holdings of Common Shares by Emera greater than 15% and up to 25% of the outstanding Common Shares are subject to a limited restriction on transfer and certain voting covenants contained in the Strategic Investment Agreement.

# 8. DIRECTORS AND OFFICERS

## 8.1 Name, Occupation and Security Holdings

The following table sets forth certain information with respect to the directors and executive officers of APUC, and information on their history with APCo and APUC. Unless otherwise indicated, the individuals have been in their principal occupations for more than five years.

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| CHRISTOPHER J. BALL<br>Toronto, Ontario, Canada<br>Age: 65 | Christopher Ball is the Executive Vice President of Corpfinance International Limited, and President of CFI Capital Inc., both of which are investment banking boutique firms. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a member of the Hydrovision International Advisory Board, was a director of Clean Energy BC, and is a recipient of the Clean Energy BC Lifetime Achievement Award. | Director of APUC since October 27, 2009.<br>Trustee of APCo since October 22, 2002 |
| LINDA BEAIRSTO<br>Oakville, Ontario, Canada<br>Age: 55 | Ms. Beairsto has been Chief General Counsel and Corporate Secretary for APUC since June 2011. Previously, she held various diverse roles including Commercial Real Estate Lawyer at Fasken Martineau, Special Counsel at E.I. du Pont Canada Inc., Director of Legal Services at Patheon Inc., Executive Vice-President & Chief Legal Counsel at ABC Group of Companies and Special Counsel at Allergan Inc. Ms. Beairsto earned a Bachelor of Arts Degree from the University of British Columbia and a Bachelor of Laws Degree from the University of New Brunswick. She was called to the Ontario Bar in 1990. In 2013, Ms. Beairsto completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). | Officer of APUC since June 6, 2011 |
| DAVID BRONICHESKI<br>Oakville, Ontario, Canada<br>Age: 56 | Mr. Bronicheski is the Chief Financial Officer (“**CFO**”) of APUC. He has held various senior management positions including Executive Vice President and CFO of a publicly traded income trust providing local telephone, cable television and internet service. He was also CFO for a large public hospital in Ontario. Mr. Bronicheski holds a Bachelor of Arts in economics (cum laude), a Bachelor of Commerce degree and an MBA (University of Toronto, Rotman School of Management). He is also a Chartered Accountant and a Chartered Professional Accountant. | Officer of APUC since October 27, 2009.<br>Officer of APCo since September 17, 2007 |
| CHRISTOPHER HUSKILSON<br>Wellington, Nova Scotia, Canada<br>Age: 58 | Christopher Huskilson has been the President and Chief Executive Officer of Emera, a North American energy and services company, since November 2004. He is also Chair of Emera Maine, a Director of Nova Scotia Power Inc. and serves as the Chair or as a Director of a number of other Emera affiliated companies. Mr. Huskilson has held a number of positions within Nova Scotia Power Inc. and its predecessor, Nova Scotia Power Corporation, since June 1980. Mr. Huskilson holds a Bachelor of Science in Engineering and a Master of Science in Engineering from the University of New Brunswick. | Director of APUC since October 27, 2009.<br>Trustee of APCo since July 27, 2009 |
| CHRISTOPHER K. JARRATT<br>Oakville, Ontario, Canada<br>Age: 57 | Christopher Jarratt has over 25 years of experience in the independent electric power and utility sectors. Mr. Jarratt is a founder and principal of APCI, a private independent power developer formed in 1988 which is the predecessor organization to APCo and APUC. Between 1997 and 2009, Mr. Jarratt was a principal in Algonquin Power Management Inc. which managed APCo (formerly Algonquin Power Income Fund). Since 2010, Mr. Jarratt has been a board member and served as Vice Chair of APUC. Prior to 1988, Mr. Jarratt was a founder and principal of a consulting firm specializing in renewable energy project development and environmental approvals. Mr. Jarratt earned an Honours Bachelor of Science degree from the University of Guelph in 1981 specializing in water resources engineering and holds an Ontario Professional Engineering designation. In 2009, Mr. Jarratt completed the Chartered Director program of the Directors College (McMaster University) and holds the certification of Ch. Dr. (Chartered Director). In addition, Mr. Jarratt was co-recipient of the 2007 Ernst & Young Entrepreneur of the Year finalist award. | Director of APUC since June 23, 2010. |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| KENNETH MOORE<br>Toronto, Ontario, Canada<br>Age: 57 | Kenneth Moore is the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie & Co., a Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). | Director of APUC since October 27, 2009.<br>Trustee of APCo since December 18, 1998 |
| DAVID PASIEKA<br>Oakville, Ontario, Canada<br>Age: 59 | David Pasieka is the President of APUC's Distribution Group. As President, Mr. Pasieka is focused on acquiring and managing a portfolio of regulated water, natural gas and electrical companies throughout the United States. The focus of the portfolio is in the distribution, transmission, and generation sectors. Mr. Pasieka has global experience in strategy, sales, marketing, integration, operations and customer service. He has led many organizations while integrating people, process and technology to encourage the steady growth of the organizations. Mr. Pasieka holds a Bachelor of Science Degree from the University of Waterloo, Masters of Business Administration from the Schulich School of Business –York University and a Chartered Director designation from McMaster University. | President - Liberty Utilities (Canada) Corp. since September 1, 2011 |
| IAN E. ROBERTSON<br>Oakville, Ontario, Canada<br>Age: 56 | Ian Robertson is the Chief Executive Officer of the Corporation. Mr. Robertson is a founder and principal of APCI, a private independent power developer formed in 1988 which was a predecessor organization to APUC. Mr. Robertson has over 23 years of experience in the development of electric power generating projects and the operation of diversified regulated utilities. Mr. Robertson is an electrical engineer and holds a Professional Engineering designation through his Bachelor of Applied Science degree awarded by the University of Waterloo. Mr. Robertson earned a Master of Business Administration degree from York University and holds a Chartered Financial Analyst designation. Additionally, he has completed the Chartered Director program of the Directors College (McMaster University), as well as a Global Professional Master of Laws degree from the University of Toronto and has the certification of Ch. Dir. (Chartered Director). Commencing in 2013, Mr. Robertson has served on the Board of Directors of the American Gas Association. | Director of APUC since June 23, 2010. |
| MASHEED SAIDI<br>Dana Point, California, United States<br>Age: 61 | Masheed Saidi has over 30 years of operational and business leadership experience in the electric utility industry. Ms. Saidi is an Executive Consultant of Energy Initiatives Group, a specialized group of experienced professionals that provide technical, commercial and business consulting services to utilities, ISOs, government agencies and other organizations in the energy industry. Between 2005 and 2010, Ms. Saidi was the Chief Operating Officer and Executive Vice President of US Transmission for National Grid USA, for which she was responsible for all aspects of US transmission business. Ms. Saidi is a member of the Board of Directors for the non-profit organization Mary's Shelter and previously served on the Board of Directors on the Northeast Energy and Commerce Association. She earned her Bachelors in Power System Engineering from Northeastern University and her Masters of Electrical Engineering from the Massachusetts Institute of Technology. She is a Registered Professional Engineer (P.E.) | Director of APUC since June 18, 2014 |
| DILEK SAMIL<br>Las Vegas, Nevada, United States<br>Age: 60 | Dilek Samil has over 30 years of finance, operations and business experience in both the regulated energy utility sector as well as wholesale power production. Ms. Samil joined NV Energy as Chief Financial Officer and retired as Executive Vice President and Chief Operating Officer. While at NV Energy, Ms. Samil completed the financial transformation of the company bringing its financial metrics in line with those of the industry. As Chief Operating Officer, Ms. Samil focused on enhancing the company's safety and customer care culture. Prior to her role at NV Energy, Ms. Samil gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power. During her tenure at CLECO, the company completed construction of its largest generating unit and successfully completed its first rate case in over 10 years. Ms. Samil also served as CLECO's Chief Financial Officer at a time when the industry and the company faced significant turmoil in the wholesale markets. She led the company's efforts in the restructuring of its wholesale and power trading activities. Prior to NV Energy and Cleco, Ms. Samil spent about 20 years at NextEra where she held positions of increasing responsibility, primarily in the finance area. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida. | Director of APUC since October 1, 2014 |

| Name and Place of Residence | Principal Occupation | Served as Director or Officer of APUC from |
|---|---|---|
| MIKE SNOW<br>Markham, Ontario, Canada<br>Age: 55 | Mike Snow is the President of APUC's Generation Group and is responsible for all aspects of strategy, business development, operations, asset management, human resources, and evaluating and reporting on growth and operational activities. Mr. Snow has led both industrial and consumer organizations focused on growth and international operations in Mexico, South America, and Asia, while driving culture change and building strong leadership teams. Mike holds a Bachelor of Science Degree in Math from Dalhousie University, a Bachelor of Engineering Degree (Mechanical) from the Technical University of Nova Scotia, and a Masters of Business Administration from the Richard Ivey School of Business – University of Western Ontario. | Officer of APUC since July 4, 2011 |
| GEORGE L. STEEVES<br>Aurora, Ontario, Canada<br>Age: 66 | George Steeves is the principal of True North Energy, an energy consulting firm specializing in the provision of technical and financial due diligence services for renewable energy projects. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the President of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a chair, director and/or audit committee member of public and private companies, including the Corporation, and formerly Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University and holds the Professional Engineering designation in Ontario and British Columbia. Additionally he has completed the Chartered Director program of the Directors College (McMaster University) and has the certification of Ch. Dir. (Chartered Director). | Director of APUC since October 27, 2009.<br>Trustee of APCo since September 8, 1997 |
| GEORGE TRISIC<br>Oakville, Ontario, Canada<br>Age: 55 | George Trisic is the Senior Vice President of Business Services for the Corporation, and has broad experience managing in high growth, start up and expanding businesses across multiple sites and regions. In his role, Mr. Trisic is responsible for shared services for the Corporation including information technology, human resources, communications, legal, and procurement, and is a well-regarded team builder and business partner. His skill set includes leading multi-functional groups in finance, human resources, legal, and information technology in a senior role. Mr. Trisic earned a Bachelor of Law Degree from the University of Western Ontario in 1984. | Officer of APUC since November 4, 2013 |

Each director will serve as a director of APUC until the next annual meeting of shareholders or until his or her successor is elected in accordance with the by-laws of APUC (the **"By-Laws"**).

As at March 11, 2016, the directors and executive officers of APUC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 987,442 Common Shares, representing less than one percent of the total number of Common Shares outstanding before giving effect to the exercise of Options or warrants to purchase Common Shares held by such directors and executive officers. The statement as to the number of Common Shares beneficially owned, directly or indirectly, or over which control or direction is exercised by the directors and executive officers of APUC as a group is based upon information furnished by the directors and executive officers.

## 8.2 Audit Committee

Under the By-Laws, the directors may appoint from their number, committees to effect the administration of the director's duties. The directors have established an Audit Committee comprised of three directors of APUC, Mr. Ball (Chairman), Mr. Moore and Ms. Samil, all of whom are independent and financially literate for purposes of National Instrument 52-110 - Audit Committees. The Audit Committee is responsible for reviewing significant accounting, reporting and internal control matters, reviewing all published quarterly and annual financial statements and recommending their approval to the Directors and assessing the performance of APUC's auditors.

### 8.2.1 Audit Committee Charter

The charter for Audit Committee is attached as Schedule F to this AIF.

### 8.2.2 Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as directors of APUC, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Moore has extensive financial experience and is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the designation of Ch. Dir. (Chartered Director)

Ms. Samil has extensive financial experience, with over 30 years of finance, operations and business experience in the regulated energy utility sector. During her career, Ms. Samil was the Executive Vice President and Chief Operating Officer of NV Energy and gained considerable experience in generation and system operations as President and Chief Operating Officer for CLECO Power LLC. Ms. Samil holds a Bachelor of Science from the City College of New York and a Masters of Business Administration from the University of Florida.

### 8.2.3 Pre-Approval Policies and Procedures

All non-audit services proposed to be provided by APUC's auditors must be approved by the directors prior to the auditors providing such services.

KPMG LLP was the external auditor of APUC until March 22, 2013, when Ernst & Young LLP's appointment as external auditor of APUC became effective. For the financial years ended December 31, 2015, December 31, 2014 and December 31, 2013, Ernst & Young LLP and KPMG LLP charged the following fees to APUC respectively:

| Services | 2015 Fees ($) | 2014 Fees ($) | 2013 Fees ($) (KPMG LLP)[5] | 2013 Fees ($) (Ernst & Young LLP)[6] | 2013 Total Fees |
|---|---|---|---|---|---|
| Audit Fees[1] | 2,420,650 | 1,965,600 | 351,000 | 1,242,000 | 1,593,000 |
| Audit-Related Fees[2] | 98,835 | 293,858 | — | 40,806 | 40,806 |
| Tax Compliance Fees[3] | — | — | 86,575 | — | 86,575 |
| Other Tax Fees[4] | 375,600 | 101,605 | 141,722 | 40,000 | 181,722 |
| All Other Fees | 19,500 | 28,000 | 61,100 | — | 61,100 |

1 For professional services rendered for audit or review or services in connection with statutory or regulatory filings or engagements.

2 For assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements and not reported under Audit Fees, including audit procedures relate to regulatory commission filings and the audit of defined benefit pension plans.

3 For preparation of income and other tax filings.

4 For tax advisory and planning services.

5 For the period from January 1, 2013 to March 22, 2013, when KPMG LLP's resignation as auditor of APUC became effective. KPMG LLP provided additional tax services to APUC after KPMG LLP ceased to be the external auditor for APUC. The fees for such services are not included in the above table.

6 For the period commencing March 22, 2013, when Ernst & Young LLP's appointment as external auditor of APUC became effective, until December 31, 2013.

## 8.3 Corporate Governance and Compensation Committees

The directors have also established a Corporate Governance Committee ("CGC") comprised of four of the directors of APUC, Mr. Steeves (Chair), Mr. Huskilson Ms. Saidi, and Mr. Moore. The CGC typically includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

The directors have also put in place a Compensation Committee ("CC"), comprised of three directors of APUC, Ms. Samil (Chair), Mr. Ball, and Ms. Saidi. The CC typically includes two members of management by invitation, Mr. Robertson and Mr. Jarratt.

## 8.4 Bankruptcies

Mr. Moore was a director of Telephoto Technologies Inc., a private sports and entertainment media company. Telephoto Technologies Inc. was placed into receivership in August, 2010 by Venturelink Funds. Mr. Moore resigned from the board of directors of Telephoto Technologies Inc. in April, 2010.

David Pasieka, the President of Liberty Utilities, was a director of Luxell Technologies Inc. when it filed a proposal under the Bankruptcy and Insolvency Act (Canada) on September 27, 2006. Luxell Technologies Inc. received a Certificate of Full Performance of Proposal under such legislation through a letter issued by its trustee in bankruptcy on January 14, 2008.

## 8.5 Potential Material Conflicts of Interest

Other than as set out below or disclosed elsewhere in this AIF (including Section 3.4, Business Associations with APMI and Senior Executives) and APUC's financial statements and MD&A for the fiscal year ended December 31, 2015, APUC is not aware of any existing or potential material conflicts of interest between APUC or a subsidiary and any current director or officer of APUC or a subsidiary. Mr. Huskilson is a director of APUC but is also the President and CEO of Emera. Emera is a major shareholder of APUC. Emera has a strategic relationship with APUC, see "*Material Contracts*". Mr. Huskilson does not vote in Board meetings on matters involving APUC's relationship with Emera nor on matters involving a potential conflict between APUC and Emera.

# 9. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

## 9.1 Legal Proceedings

Except as disclosed elsewhere in this AIF, the only legal proceedings involving APUC or its subsidiaries that were material in 2015 are as follows:

### (i) Trafalgar proceedings

Trafalgar Power Inc. ("**Trafalgar**") commenced an action in 1999 in U.S. District Court against APUC, and various other entities related to them in connection with, among other things, the sale of the Trafalgar Class B Note by Aetna Life Insurance Company to APUC and in connection with the foreclosure on the security for the Trafalgar Class B Note which includes interests in the Trafalgar entities and in the hydroelectric generating facilities in New York (the "**Trafalgar Hydro Facilities**"). Over the past 16 years there have been various legal proceedings and appeals in connection with this matter. Both the Algonquin entities and Trafalgar had certain motions before the Bankruptcy Court seeking determinations on a number of matters. On November 13, 2015, the Bankruptcy Court entered judgment that: (1) grants the Coporation's motion for summary judgment; (2) denies Trafalgar's' motion for summary judgment; and (3) dismisses Trafalgar's Adversary Complaint on the merits. Trafalgar has appealed the Judgment. Trafalgar has brought a motion for reconsideration of this judgment.

Additionally, Trafalgar has alleged in various pleadings before the Bankruptcy Court that the Algonquin entities have mismanaged the operations of the Trafalgar Hydro Facilities (now sold as noted below) under that certain management agreement dated January 15, 1996 (the "**Management Agreement**"). No demand has been made based on these allegations. Any such claims are subject to an arbitration clause under the Management Agreement. The Corporation denies any liability under either the 1995 agreement or the Management Agreement and will continue to vigorously defend against these claims.

The Bankruptcy Court has approved the sale of all seven of the Trafalgar Hydro Facilities all of which have now been closed. The parties are attempting to settle this long standing lawsuit through mediation.

### (ii) Côte Ste-Catherine Water Lease Dues

On December 19, 1996, the Attorney General of Québec (the "**Québec AG**") filed suit in Québec Superior Court against Algonquin Dévelopment (Côte Ste-Catherine) Inc. (Dévelopment Hydromega), a predecessor company to a subsidiary entity of APUC. The Québec AG at trial claimed $5.4 million for amounts that Algonquin Dévelopment Côte Ste-Catherine Inc. had been paying to St. Lawrence Seaway Management Corporation ("**Seaway Management**") under the water lease relating to the Côte Ste-Catherine Hydro Facility. Algonquin Dévelopment (Côte Ste-Catherine) Inc. brought the Attorney General of Canada into the proceedings. On March 27, 2009, the Superior Court dismissed the claim of the Québec AG. Québec AG appealed this decision on April 24, 2009, and the appeal was heard in January 2011.

On October 21, 2011 the Québec Court of Appeal ordered Algonquin Dévelopment (Côte Ste-Catherine) Inc. to pay approximately $5.4 million (including interest) to the government of Québec relating to water lease payments that Algonquin Dévelopment (Côte Ste-Catherine) Inc. has been paying to the Seaway Management under the water lease in prior years. The water lease with Seaway Management contains an indemnification clause which management believes mitigates this claim and management intends to vigorously defend its position. The potential unrecoverable loss, if any, for the related prior periods could be up to $6.8 million. The parties are attempting to resolve this matter through good faith negotiations.

### (iii) Long Sault Global Adjustment Claim

In December 2012, N-R Power and Energy Corporation, the LS Partnership, and N-R Power Partnership ("**Long Sault**") commenced proceedings (together with the other similarly affected non-utility generators) against the OEFC relating to the OEFC's interpretation of certain provisions of a PPA between Long Sault and the OEFC, in relation to the use of the global adjustment as a price escalator. On March 12, 2015, the Ontario Superior Court of Justice ruled that the methodology that the OEFC used from January 1, 2011, onward to calculate payments under Long Sault's PPA, and those of other producers, did not comply with the terms of those PPAs. The decision further requires the OEFC to revert to its pre-2011 methodology for calculating payments and to pay producers the difference between the payments calculated by the OEFC since 2011 and the amount of the payments they would have received using the pre-2011 methodology, plus interest and costs. On April 10, 2015, the OEFC appealed to the Court of Appeal to set aside the Divisional Court's judgment of March 12, 2015. The appeal was heard on December 14 and December 15, 2015; the Court has reserved judgment.

## 9.2 Regulatory Actions

Except as disclosed elsewhere in this AIF, during the financial year ended December 31, 2015, there have been:

(a) no penalties or sanctions imposed against APUC by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against APUC that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that APUC has entered into with a court relating to securities legislation or with a securities regulatory authority.

Except as disclosed elsewhere in this AIF, the only regulatory action involving APUC or its subsidiaries that is material in 2015 is as follows:

### (i) Park Water Condemnation

On January 8, 2016, the Corporation acquired the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp. ("**Park Water**") which owns and operates three regulated water utilities engaged in the production, treatment, storage, distribution, and sale of water in Southern California and Western Montana. Park Water provides, owns and operates a water system in central Los Angeles. Apple Valley owns and operates the Apple Valley Ranchos Water System in Apple Valley, California. Mountain Water owns and operates the water system serving the municipality of Missoula, Montana. Mountain Water and Apple Valley are wholly-owned by Park Water.

Mountain Water is currently the subject of a condemnation proceeding by the city of Missoula. It is not known when the condemnation proceeding will conclude or whether the city of Missoula will ultimately take possession of Mountain Water. The City's right to take Mountain Water is currently on appeal before the Montana Supreme Court. The Commissioners' award as part of the condemnation proceeding established the value of Mountain Water's assets at US$88.6 million. It is believed that Mountain Water would also be entitled to reimbursement of attorney's fees plus payment of interest accruing at the rate of 10% per annum since May 2014 under Montana statutes. Accrued interest is currently estimated to be US$14 million. The Commissioners' award of US$88.6 million and the final award ordered by the Missoula District Court also are subject to appeal to the Montana Supreme Court. The City of Missoula has contested payment of interest in the condemnation proceeding. If the City of Missoula ultimately takes possession of Mountain Water, the compensation to be paid by the City of Missoula for such taking will be the value of the utility plus accrued interest and attorney's fees as determined by the Montana court. On December 22, 2015, various developers filed a Petition for Declaratory and Other Relief in Missoula County District Court against Mountain Water and the City of Missoula. The lawsuit pertains to funded by others ("**FBO**") contracts between each developer and Mountain Water. Under those FBO contracts, the developers paid for facilities to provide water service. Mountain Water agreed to refund those developer advances under the FBO contracts over a 40 year period. These FBO contracts represent a liability of US$22 million on the balance sheet of Mountain Water. While there is no allegation of breach by Mountain Water under the FBO contracts, the developers are seeking to enforce these refunds should the utility be transferred to the city. That lawsuit is ongoing and is in the early stages of litigation. In addition, MNPSC has asserted that the indirect change of control of Mountain Water required its approval and is, therefore, investigating potential changes to the rates of Mountain Water. MNPSC has also expressed an intention to seek penalties against Mountain Water. The MNPSC has acknowledged that it has no express authority over the acquisition transaction under statute, but has asserted that such authority should be implied. These matters are in the early stages.

On January 8, 2016, the Town of Apple Valley filed an eminent domain complaint against Apple Valley. In California, parties to a condemnation case typically agree for the case to be bifurcated into two phases. The first phase will determine the necessity of the taking. The second phase will involve the valuation of the utility assets. If the Town of Apple Valley is successful in the right to take proceeding, a second phase will be held to determine the fair market value of Apple Valley. At present, a trial setting conference has been set for July 7, 2016. The matter is expected to take two to three years to resolve. The condemnation action has potential financial implications for Liberty Utilities depending on the outcome of the condemnation process. In the event that the Town of Apple Valley prevails in the necessity phase of the condemnation case, the financial impact of the condemnation case will depend on the ultimate determination of the fair market value of Apple Valley's assets by a jury, if so elected by either party, along with a determination of interest and attorney's fees by the court.

# 10. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this AIF, and as disclosed in APUC's annual financial statements and MD&A as at and for the periods ended December 31, 2015, 2014 and 2013, management has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial years or during the current financial year that has materially affected or will materially affect APUC.

# 11. TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Common Shares, the Series A Shares and the Series D Shares is CST Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, and Halifax.

# 12. MATERIAL CONTRACTS

Except for certain contracts entered into in the ordinary course of business of APUC and its subsidiaries, the contracts described below are the only contracts entered into by APUC or its subsidiaries during 2015 (or prior to 2015 in the case of contracts that are still in effect) that are material to APUC:

(a) **APCo debentures:** APCo Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of senior unsecured debentures from time to time. A First Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated July 25, 2011 providing for the issuance of $135,000,000 5.50% senior unsecured debentures due July 25, 2018. The notes are interest only until maturity. The funds were used to repay borrowings as it related to the construction of the St. Leon Wind Facility and to reduce outstanding indebtedness under the APCo Credit Facility (as defined below). Second Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated December 3, 2012 providing for the issuance of $150,000,000 4.82% senior unsecured debentures due February 15, 2021. Third Supplemental Trust Indenture between APCo and BNY Trust Company of Canada dated January 17, 2014 providing for the issuance of $200,000,000 4.65% senior unsecured debentures due February 15, 2022.

(b) **APCo Credit Facility:** Sixth amended and restated credit agreement between APCo, Corporation Fleur de Lis Eolinnes Saint-Damase Commandite, APUC, National Bank of Canada as administrative agent and certain financial institutions dated as of July 31, 2014 providing for a $350 million senior unsecured credit facility with a maturity date of July 31, 2019 (the "**APCo Credit Facility"**).

(c) **U.S. Debt Private Placements:** Trust Indenture dated July 2, 2012 between LU GP1 and The Bank of New York Mellon providing for the issuance of senior unsecured debentures. First Supplemental Indenture dated July 2, 2012 between LU GP1, Liberty Utilities. and The Bank of New York Mellon in connection with a U.S. $225 million private placement of senior notes maturing between July 31, 2017 and July 30, 2027. Second Supplemental Indenture dated March 14, 2013 between LU GP1, Liberty Utilities. and The Bank of New York Mellon in connection with a U.S. $15 million private placement of senior notes due March 13, 2023. Third Supplemental Indenture dated July 31, 2013 between LU GP1, Liberty Utilities. and The Bank of New York Mellon in connection with a U.S. $125 million private placement of senior notes maturing between July 31, 2020 and July 31, 2028. Fourth Supplemental Indenture dated April 30, 2015 between Liberty Utilities Finance GP1, Liberty Utilities Co. and The Bank of New York Mellon in connection with a US $160 million private placement of senior notes maturing between April 30, 2045 and July 15, 2045.

(j) **Western Water Acquisition:** Plan and Agreement of Merger, among Liberty Utilities , Liberty WWH, Inc., and Western Water Holdings, LLC, dated as of September 19, 2014, pursuant to which Liberty Utilities (by merger of Liberty WWH, Inc. with and into Western Water Holdings, LLC) acquired Western Water Holdings, LLC and, indirectly, its subsidiaries Park Water, Apple Valley., and Mountain Water, on January 8, 2016.. The payment obligations of Liberty Utilities and Liberty WWH, Inc. under such merger agreement are guaranteed pursuant to a Guaranty, dated as of September 19, 2014, by Algonquin Power & Utilities Corp. in favor of the equity holders of Western Water Holdings, LLC immediately prior to such merger.

(e) **Underwriting Agreement:** Underwriting Agreement between APUC and CIBC World Markets Inc. and TD Securities Inc., as Joint Bookrunners, dated November 25, 2015, providing for issuance and sale of 14,355,000 Common Shares at a price of $10.55 per share for an aggregate purchase price of $150,009,750.

(f) **Empire Acquisition:** Agreement and Plan of Merger, dated as of February 9, 2016, by and among Empire, Liberty Utilities (Central) Co., and Liberty SubCo. pursuant to which Liberty Utilities (Central) Co. has agreed to acquire Empire and (indirectly) its subsidiaries by merger of Liberty Sub Corp. with and into Empire. APUC guaranteed the payment and performance of all obligations of Liberty Utilities (Central) Co. under the Agreement and Plan of Merger pursuant to a Guarantee dated as of February 9, 2016, by APUC in favor of Empire. Consummation of the Merger remains subject to satisfaction of the conditions thereto set forth in the foregoing Agreement and Plan of Merger. For further discussion please see section 2.3, Recent Developments.

(g) **Underwriting Agreement:** Underwriting Agreement dated February 15, 2016, between LU Canada, as the selling debenture holder, and CIBC World Markets Inc. and Scotia Capital Inc. as co-lead Underwriters, providing for the issuance and sale of not less than $1,000,000,000 and up to $1,150,000,000 principal amount of Debentures.

(h) **Trust Indenture:** Trust Indenture dated as of March 1, 2016, between APUC and CST Trust Company, as trustee, providing for the creation and issuance of up to $1,150,000,000 principal amount of Debentures.

(i) **Installment Receipts and Pledge Agreement:** Installment Receipt and Pledge Agreement, dated March 1, 2016, between APUC, LU Canada, as the selling debenture holder, CIBC World Markets Inc., Scotia Capital Inc., BMO Nesbitt Burns Inc., National Bank Financial Inc., RBC Dominion Securities Inc., TD Securities Inc., Desjardins Securities Inc., Raymond James Ltd., J.P. Morgan Securities Canada Inc., Wells Fargo Securities Canada, Ltd., Industrial Alliance Securities Inc., Canaccord Genuity Corp. and Cormark Securities Inc., and the Underwriters, and CST Trust Company, as custodian. The foregoing provides for the issuance of installment receipts to evidence beneficial ownership of the Debentures for the period from payment of the First Instalment until payment Final Instalment.

## 13. INTERESTS OF EXPERTS

Ernst & Young LLP is the external auditor of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulation, and that they are independent accountants with respect to the Corporation under all relevant U.S. professional and regulatory standards.

## 14. ADDITIONAL INFORMATION

Additional information relating to APUC may be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of APUC's securities and securities authorized for issuance under equity compensation plans is contained in APUC's information circular for its most recent annual meeting. Additional financial information is provided in APUC's financial statements and management discussion and analysis MD&A for the year ended December 31, 2015.

SCHEDULE A

Location

## Renewable - Hydroelectric, Solar and Wind Facilities

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Hydroelectric - Ontario Facilities** | | | | | |
| **Facility:** Long Sault Rapids Hydro Facility<br><br>**Owner**: Algonquin Power (Long Sault) Partnership and N-R Power Partnership | 18 | Abitibi River near Cochrane, Ontario | **Electricity Purchaser:** OEFC<br><br>**Rates:** $0.0957/kW-hr (average estimate) | 111,600 | 2048 |
| **Facility:** Hurdman Dam Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 0.6 | Mattawa River near Mattawa, Ontario | **Electricity Purchaser:** IESO (formerly, the Ontario Power Authority)<br><br>**Rates**: $0.08725/kW-hr Paid on Hydroelectric Contract Incentive rate | 3,150 | 2031 |
| **Facility:** Campbellford Hydro Facility<br><br>**Owner**: Algonquin Power (Campbellford) Limited Partnership<br>**Owner**: Leased from Campbellford Public Utilities Commission, with lease expiring in 2018 | 4 | Trent River near Campbellford, Ontario | **Electricity Purchaser:** OEFC<br><br>**Rates**: $0.0435/kW-hr (average estimate) | 26,250 | 2019 |
| **Hydroelectric – Québec Facilities** | | | | | |
| **Facility:** Saint-Alban Hydro Facility<br><br>**Owner**: Nominee owner is SNC Lavalin Inc., beneficial owner is Algonquin Power Fund (Canada) Inc. | 8.2 | Ste-Anne River near the Village of Saint-Alban, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.0857/kW-hr | 37,650 | 2016 |
| **Facility:** Glenford Hydro Facility<br><br>**Owner**: Société en Commandite Chute Ford | 5 | Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.0857/kW-hr | 24,000 | 2020 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Rawdon Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.5 | Ouareau River near the Village of Rawdon, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.0832/kW-hr (Jan-May) | 15,200 | 2014<br><br>PPA renewal option has been exercised to extend PPA to 2034[5] |
| **Facility:** Côte Ste-Catherine Hydro Facility<br><br>**Owner**: Algonquin Power (Mont-Laurier) Limited Partnership | 11.1 | St. Lawrence River near the Town of Ste.-Catherine, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: Phase I Energy $0.05700/kW-hr | Phase 1: 13,800 | Phase 1: 2020 |
| | | | Phase II Energy $0.07309/kW-hr Capacity $179.37/kW* | Phase II: 35,100 | Phase II: 2018 PPA has renewal option to 2043 |
| | | | Phase III Energy $0.0761/kW-hr Capacity $188.08/ kW*<br>* calculated over the average kilowatt output over the period December to March | Phase III: 34,750 | Phase III: 2020 PPA has renewal option to 2045 |
| **Facility:** Ste-Raphaël Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 3.5 | Rivière de Sud near Québec City, Québec | **Electricity Purchaser**: Hydro-Québec<br><br>**Rates**: $0.0832/kW-hr (Jan - Feb) | 21,650 | 2014<br><br>PPA renewal option has been exercised to extend PPA to 2034[5] |
| **Facility:** Mont Laurier Hydro Facility<br><br>**Owner**: Algonquin Power (Mont-Laurier) Limited Partnership | 2.7 | Rivière-du-Lièvre in the Town of Mont Laurier, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.06231/kW-hr | 20,100 | 2027 |
| **Facility :** Rivière-du-Loup Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.6 | Rivière-du-Loup near the Town of Rivière-du-Loup, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.0857/kW-hr | 17,250 | 2015<br><br>PPA has renewal option to 2035 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Hydraska Hydro Facility<br><br>**Owner**: Algonquin Power Trust | 2.3 | Yamaska River near the Town of St.-Hyacinthe, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: Jan - May: Summer Energy $0.070/kW-hr Winter Energy $0.1283/kW-hr | 9,100 | 2014<br><br>PPA renewal option has been exercised to extend PPA to 2034[5] |
| **Facility:** Ste-Brigitte Hydro Facility<br><br>Owner: Algonquin Power Fund (Canada) Inc. | 4.2 | Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates:** $0.0832/kW-hr (Jan-Feb) [11] | 12,550 | 2014<br><br>PPA renewal option has been exercised to extend PPA to 20345[5] |
| **Facility:** Belleterre Hydro Facility<br><br>**Owner**: Algonquin Power Fund (Canada) Inc. | 2.2 | Winneway River in the Municipality of Laforce, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: Energy $0.0693/kWh Capacity $171.35/kW | 11,150 | 2013<br><br>PPA renewal option has been exercised to extend PPA to 2033[7] |
| **Facility:** Donnacona Hydro Facility<br><br>**Owner**: Société Hydro-Donnacona, S.E.N.C. | 4.8 | Jacques Cartier River near Donnacona, Québec | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: $0.0857/kW-hr | 0 | 2022<br><br>PPA has renewal option to 2047 |
| **Facility:** Arthurville Hydro Facility<br><br>**Owner**: Algonquin Power Trust | 0.7 | Rivière du Sud downstream from Ste-Raphaël | **Electricity Purchaser:** Hydro-Québec<br><br>**Rates**: No target rate as the site is expected to be offline | 0[3] | 2013<br><br>PPA renewal option has been exercised to extend PPA to 2033[7] |
| **Hydroelectric - Western Canada Facility** | | | | | |
| **Facility:** Dickson Dam Hydro Facility<br><br>**Owner:** Algonquin Power Operating Trust | 15 | Innisfail, Alberta | **Electricity Purchaser:** AESO & Capital Power<br><br>**Rates**: $0.0608/kwh blend of AESO Market rate and CP hedge | 65,000 | 2016[6] |
| **Hydroelectric - Maritime Facilities** | | | | | |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Tinker Hydro Facility<br><br>**Owner:** Algonquin Tinker Gen Co. | 34 | Perth-Andover, New Brunswick | **Electricity Purchaser:** AES Town of Perth-Andover<br><br>**Rates:** AES ~ U.S. $0.0418/ kWhr Town of Perth Andover: ~ CDN $0.0835/kWhr | 142,000 | Perth-Andover Contract through 2021 |
| **Facility:** Caribou Hydro Facility<br><br>**Owner:** Algonquin Northern Maine Gen Co. | 0.9 | Caribou, Maine | **Electricity Purchaser:** AES<br><br>**Rates:** Energy – ~U.S. $0.0418/kWhr | 1,300 | n/a |
| **Facility:** Squa Pan Hydro Facility<br><br>**Owner:** Algonquin Northern Maine Gen Co. | 1.2 | Squa Pan Lake, near Caribou Maine | **Electricity Purchaser:** AES<br><br>**Rates:** Energy – ~U.S. $0.0418/kWhr | 700 | n/a |
| **Solar Facilities** | | | | | |
| **Facility:** Cornwall Solar Facility<br><br>**Owner:** Cornwall Solar Inc. | 10 | Cornwall, Ontario | **Electricity Purchaser:** IESO (formerly, the Ontario Power Authority)<br><br>**Rates:** $0.443/kWh | 14,800 | 2034 |
| **Facility:** Bakersfield Solar Facility<br><br>**Owner:** Algonquin SKIC20 Solar, LLC | 20 | Kern County, California | **Electricity Purchaser:** PG&E<br><br>**Rates:** $0.883/kWh | 53,100 | 2035 |
| **Facility:** Bakersfield II Solar Facility<br><br>**Owner:** Algonquin SKIC10 Solar, LLC | 10 | Kern County, California | **Electricity Purchaser:** (Under Development - PG&E) | 26,000 | 2036 (20 years after COD) |
| **Wind - Canadian Facilities** | | | | | |
| **Facility:** Morse Wind Facility<br><br>**Owner:** Algonquin Power Morse LP | 23 | Morse, Saskatchewan | **Electricity Purchaser:** SaskPower<br><br>**Rates:** $0.1040/kW-hr | 108,800 | 2035 (20 years after COD) |
| **Facility:** Red Lily Wind Facility<br><br>**Owner:** Red Lily Wind Energy Partnership | 26.4 | Saskatchewan | **Electricity Purchaser:** SaskPower<br><br>**Rates:** $0.0897/kW-hr | 88,400 | 2036 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility**: St.-Damase Wind Facility<br><br>**Owner**: Société en Commandité Fleur de Lis Éoliennes Saint-Damase | 24 | Saint-Damase, Québec | **Electricity Purchaser**: Hydro-Quebec<br><br>**Rates**: $0.0976/kW-hr | 76,000 | 2034 |
| **Facility**: St. Leon Wind Facility<br><br>**Owner**: St. Leon Wind Energy LP | 104 | St. Leon, Manitoba | **Electricity Purchaser**: Manitoba Hydro<br><br>**Rates**: Manitoba Hydro rates are confidential | 372,000 | 2026 + one 5 year extension |
| **Facility:** St. Leon II Wind Facility<br><br>**Owner**: St. Leon II Wind Energy LP | 16.5 | St. Leon, Manitoba | **Electricity Purchaser:** Manitoba Hydro<br><br>**Rates**: Manitoba Hydro rates are confidential | 58,100 | 2037 |
| **Facility:** Amherst Island Wind Facility<br><br>**Owner**: Windlectric Inc. | 75 | Stella, Ontario | **Electricity Purchaser:** (Under Development - IESO [formerly, the Ontario Power Authority]) | 247,000 | 2037 (20 years after COD) |
| **Facility**: Chaplin Wind Facility<br><br>**Owner**: Windlectric Inc. | 177 | Chaplin, Saskatchewan | **Electricity Purchaser**: (Under Development - SaskPower) | 720,000 | 2043 (25 years after COD) |
| **Wind - U.S. Facilities** | | | | | |
| **Facility:** Minonk Wind Facility<br><br>**Owner**: Minonk Wind, LLC | 200 | Minonk, Illinois | **Electricity Purchaser:** PJM North Illinois<br><br>**Rates:** market rates | 674,000 | 2022[4] |
| **Facility:** Senate Wind Facility<br><br>**Owner:** Senate Wind, LLC | 150 | Graham, Texas | **Electricity Purchaser:** ERCOT North markets<br><br>**Rates:** market rates | 520,000 | 2027[4] |
| **Facility:** Sandy Ridge Wind Facility<br><br>**Owner:** Sandy Ridge Wind, LLC | 50 | Tyrone, Pennsylvania | **Electricity Purchaser:** PJM West<br><br>**Rates:** market rates | 158,300 | 2022[4] |
| **Facility:** Shady Oaks Wind Facility<br><br>**Owner:** GSG6, LLC | 109.5 | Lee County, Illinois | **Electricity Purchaser:** Commonwealth Edison<br><br>**Rates:** market rates | 352,400 | 2032 |

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser/ 2015 Power Purchase Rates[1] | Annual Average Expected Energy Production (MW-hrs) | PPA Expiry Year |
|---|---|---|---|---|---|
| **Facility:** Odell Wind Facility<br>**Owner**: O'Dell Wind Farm, LLC. | 200 | Cottonwood, Jackson, Martin and Watonwan Counties Minnesota | **Electricity Purchaser:** (Under Development - Northern States Power) | 822,000 | 2036 (20 years after COD) |
| **Facility:** Val-Éo Wind Facility<br>**Owner**: Éoliennes Belle-Rivière, société en commandite | 24 | Saint-Gédéon, Québec | **Electricity Purchaser:** (Under Development – Hydro-Quebec) | 66,000 | 2037 (20 years after COD) |

1 2015 PPA rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable PPAs. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project

2 These rates reflect the estimated Avoided Costs of National Grid.

3 Scheduled to be offline in 2016. No decision has been made as to the timing of repairing these facilities.

4 APUC currently has hedge agreements in place in respect of each facility. See "Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation – Renewable – Wind Power - Material Facilities".

5 APUC has exercised its option to begin discussions with Hydro-Québec to enter new PPA agreements for agreements which expired in 2014. Negotiations are currently underway.

6 APUC currently has an agreement in place to hedge 75% of the target energy production at the facility. See "Production Method, Principal Markets, Distribution Methods and Material Facilities - Power Generation – Renewable – Hydroelectric - Principal Markets and Distribution Methods – Material Facilities - Dickson Dam Facility - Power Purchase Agreement".

7 APUC has exercised its option to begin discussions with Hydro-Québec to enter new PPA agreements for agreements which expired in 2013. Negotiations are currently underway.

# SCHEDULE B

## Thermal - Biomass, Cogeneration, and Diesel Facilities

| Generating Facility/Owner | Generating Capacity (MW) | Location | Electricity Purchaser / 2015 Power Purchase Rates | Annual Average Expected Energy Production (MW-hrs) | Year of Expiry of PPA | Lease Expiry Year |
|---|---|---|---|---|---|---|
| **Thermal - Biomass Facility** | | | | | | |
| **Facility:**<br>Valley Power Facility<br><br>**Owner**:<br>Valley Power L.P. | 12 | Drayton Valley, Alberta | **Electricity Purchaser:**<br>TransAlta Utilities Corporation-until May 2016;<br>Market- June to December;<br>**Rates**:<br>Energy: $0.0709/kW-hr | 35,000[1] | 2016 | Owned |
| **Thermal - Cogeneration Facilities** | | | | | | |
| **Facility:**<br>Sanger Facility<br><br>**Owner**:<br>Algonquin Power Sanger LLC (California) | 56 | Sanger, California | **Electricity Purchaser:**<br>PG&E | 140,900 | 2021 | Owned |
| | | | **Rates:**<br>US$ 0. 056/ kW-hr (estimated average)*<br>* subject to gas price indexing<br>**Capacity** – Approximately $254,800 January-April &November-December<br>Approximately $935,300 May-October | | | |
| **Facility:**<br>Windsor Locks Facility<br><br>**Owner**:<br>Algonquin Power Windsor Locks LLC | 70 | Windsor Locks, Connecticut | **Electricity Purchaser:**<br>ISO New England<br>Ahlstrom | 27,500<br>89,000 | Merchant<br>2027 | 2027 |
| | | | **Rates:**<br>ISO New England-Market Rates , included hourly energy, forward capacity and forward reserve payments<br>CT Class III REC ~US$0.2/kW-hr<br>Mill/NGC - US$0.071/kW-hr* Capacity $210,000**<br>Steam - DNM/NGC - US$10.31/1000lbs* Capacity $132,000<br>* Estimated average rate, includes variable component based on natural gas prices.<br>**Estimated average monthly rate, charges are CPI indexed.<br>Capacity Market and Spot Market – market prices | | | |
| **Thermal - Diesel Facilities** | | | | | | |
| **Facility:**<br>Tinker Thermal Facility<br><br>**Owner**:<br>Algonquin Tinker Gen Co. | 1 | Perth-Andover, New Brunswick | **Electricity Purchaser:**<br>Not Under Contract<br>**Rates**:<br>Capacity only | 0[1] | NA | Owned |

[1] Available to provide capacity only. The thermal facilities located in Northern Maine and New Brunswick are not considered strategic to APUC. As a result APUC is taking steps to shutdown these facilities.

SCHEDULE C

Location

## Wastewater and Water Distribution Facilities

| Utility | Owner | Location | Type of Utility | December 31, 2015 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| Black Mountain Sewer System | Liberty utilities (Black Mountain Sewer) Corp. | Carefree, Arizona | Wastewater | 2,497 | Pursuant to ACC decision 71865 |
| Gold Canyon Sewer System | Liberty Utilities (Gold Canyon Sewer) Corp. | Gold Canyon Arizona | Wastewater | 7,536 | Pursuant to ACC decision 69664 |
| Bella Vista Water System | Liberty Utilities (Bella Vista Water) Corp. | Sierra Vista, Arizona | Water Distribution | 9,803 | Pursuant to ACC decision 72251 |
| Tall Timbers Waste System | Liberty Utilities (Tall Timbers Sewer) Corp. | Tyler, Texas | Wastewater | 1,838 | Pursuant to TCEQ decision 2009-1381-UCR and SOAH decision 582-10-0350 |
| Woodmark Waste System | Liberty Utilities (Woodmark Sewer) Corp. | Tyler, Texas | Wastewater | 1,828 | Pursuant to TCEQ docket 2014-0064-UCR, SOAH docket 582-14-2348, PUCT docket |
| LPSCo Water & Waste System | Liberty Utilities (Litchfield Park Water & Sewer) Corp. | Litchfield, Park, Arizona | Wastewater<br>Water Distribution | 19,798<br>18,705 | Pursuant to ACC docket 74437 |
| Fox River Water & Waste System | Liberty Utilities (Fox River Water) LLC | Sheridan, Illinois | Wastewater<br>Water Distribution | 219<br>2,033 | Per customer agreement[3]<br>US $240.08<br>US $141.61 |
| Timber Creek Water & Waste System | Liberty Utilities (Missouri Water) LLC | DeSoto, Missouri | Wastewater<br>Water Distribution | 16<br>25 | Pursuant to MOPSC decision WR-2006-4025 |
| Holiday Hills Water System | Liberty Utilities (Missouri Water) LLC | Branson, Missouri | Water Distribution | 480 | Per MOPSC Case WR-2006-4025 |
| Ozark Water & Waste System | Liberty Utilities (Missouri Water) LLC | Kimberling City, Missouri | Wastewater<br>Water Distribution | 230<br>255 | Pursuant to MOPSC decision WR-2006-4025 |
| Holly Lake Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Hawkins, Texas | Wastewater<br>Water Distribution | 148<br>1,953 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Big Eddy Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Flint, Texas | Wastewater<br>Water Distribution | 468<br>1,191 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Piney Shores Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | Conroe, Texas | Wastewater<br>Water Distribution | 269<br>274 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |

Location:

| Utility | Owner | Location | Type of Utility | December 31, 2015 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| Hill Country Water & Waste System | Liberty Utilities (Silverleaf Water) LLC | New Braunfels, Texas | Wastewater<br>Water Distribution | 407<br>225 | Pursuant to TCEQ decision 2009-2087-UCR & SOAH decision 582-10-2369 |
| Rio Rico Water & Waste System | Liberty Utilities (Rio Rico Water & Sewer) Corp. | Rio Rico, Arizona | Wastewater<br>Water Distribution | 2,352<br>6,929 | Pursuant to ACC decision 73996 |
| Northern Sunrise Water System | Liberty Utilities (Northern Sunrise Water) Corp. | Sierra Vista, Arizona | Water Distribution | 363 | Pursuant to ACC decision 72251 |
| Southern Sunrise Water System | Liberty Utilities (Southern Sunrise Water) Corp. | Sierra Vista, Arizona | Water Distribution | 859 | Pursuant to ACC decision 72251 |
| Entrada Del Oro Waste System | Liberty Utilities (Entrada Del Oro Sewer) Corp. | Gold Canyon, Arizona | Wastewater | 337 | Pursuant to ACC decision 68306 |
| Seaside Resort Water & Waste System | Liberty Utilities (Seaside Water) LLC | Galveston, Texas | Water Distribution<br>Wastewater | 156<br>156 | Per customer agreement[2]<br>US $166.68<br>US $165.45 |
| Noel Water System | Liberty Utilities (Missouri Water) LLC | Noel, Missouri | Water Distribution | 662 | Pursuant to MOPSC decision WR-2009-0395 |
| KMB Water & Waste System | Liberty Utilities (Missouri Water) LLC | Jefferson, Franklin and Cape Girardeau counties in Missouri | Wastewater<br>Water Distribution | 185<br>531 | Pursuant to MOPSC decision WO-2010-0345 |
| Pine Bluff Water System | Liberty Utilities (Pine Bluff Water) Inc. | Pine Bluff, Arkansas | Water Distribution | 17,990 | Pursuant to APSC docket No. 14-020-U |
| White Hall Water System | Liberty Utilities (White Hall Water) Corp., and Liberty Utilities (White Hall Sewer) Corp. | White Hall, Arkansas | Wastewater<br>Water Distribution | 1,832<br>1,932 | Pursuant to City Ordinance Nos. 477 and 478 |
| **Total connections ( Not Including Park Water )** | | | | **104,482** | |

| Utility | Owner | Location | Type of Utility | December 31, 2015 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| Liberty Utilities (Park Water) Corp. | Western Water Holdings, LLC | Downey, California | Water Distribution | 29,815 | Pursuant to CPUC docket 16-01-009 |
| Liberty Utilities (Apple Valley Ranchos Water) Corp. | Liberty Utilities (Park Water) Corp. | Apple Valley, California | Water Distribution | 21,040 | Pursuant to CPUC docket 15-11-030 |
| Mountain Water Company | Liberty Utilities (Park Water) Corp. | Missoula, Montana | Water Distribution | 23,632 | Pursuant to MPSC docket D2012.7.81, Order No. 7251c |
| **Total connections ( Park Water Acquired on January 8, 2016 )** | | | | **74,487** | |

1 Inclusive of vacant connections.

2 See www.libertyutilities.com for complete rate tariffs.

3 Rates charged per agreement with developer.

# SCHEDULE D

## Electrical Distribution Facilities

| Utility | Owner | Location | Type of Utility | December 31, 2015 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| CalPeco Electric System | Liberty Utilities (CalPeco Electric) LLC | Lake Tahoe, California | Electricity Distribution | Residential – 42,940<br><br>Commercial & Industrial – 5,557 | Rates pursuant to CPUC docket 12-11-030 |
| Granite State Electric System | Liberty Utilities (Granite State Electric) Corp | Salem, New Hampshire | Electricity Distribution | Residential – 38,250<br><br>Commercial & Industrial – 6,529 | Rates pursuant to NHPUC docket DE 13-063, Order 25,638 |
| **Total Connections** | | | | **93,276** | |

1 Inclusive of vacant connections.

2 See www.libertyutilities.com for complete rate tariffs.

# SCHEDULE E

Location:

## Natural Gas Distribution Facilities

| Utility | Owner | Location | Type of Utility | December 31, 2015 Connections[1] | Rates[2] |
|---|---|---|---|---|---|
| EnergyNorth Gas System | Liberty Utilities (EnergyNorth Natural Gas) Corp. | Manchester, New Hampshire | Natural Gas Distribution | Residential – 80,327<br>Commercial & Industrial – 9,645 | Rates pursuant to NHPUC docket DG 14-180, Order 25,797 |
| Peach State Gas System | Liberty Utilities (Peach State Natural Gas) Corp. | Columbus, Gainesville, GA | Natural Gas Distribution | Residential – 60,022<br>Commercial & Residential – 4,325 | Rates pursuant to GPSC docket #34734 Document #156121 |
| New England Gas System | Liberty Utilities (New England Natural Gas Company) Corp. | Fall River, North Attleboro, Plainville, Westport, Swansea, Somerset, Massachusetts | Natural Gas Distribution | Residential – 50,550<br>Commercial & Industrial – 3,665 | Rates pursuant to M.D.P.U 10-114 |
| Midstates Gas System - Illinois | Liberty Energy (Midstates Natural Gas) Corp. | Salem, Virden, Vandalia, Xenia, Metropolis, Illinois | Natural Gas Distribution | Residential – 20,716<br>Commercial & Industrial – 2,176 | Rates pursuant to ICC decision IL-14-0371 |
| Midstates Gas System - Iowa | Liberty Energy (Midstates Natural Gas) Corp. | Keokuk, Iowa | Natural Gas Distribution | Residential – 3,881<br>Commercial & Industrial – 492 | Rates pursuant to IUB decision TF-01-68 |
| Midstates Gas System - Missouri | Liberty Energy (Midstates Natural Gas) Corp. | Jackson, Sikeston, Butler, Kirksville, Hannibal, Missouri | Natural Gas Distribution | Residential – 49,689<br>Commercial & Industrial – 6,999 | Rates pursuant to MOPSC decision GR-2014-0152 |
| **Total Connections** | | | | **292,485** | |

1 Inclusive of vacant connections. Excludes Transportation connections.

2 See www.libertyutilities.com for complete rate tariffs.

SCHEDULE F

# ALGONQUIN POWER & UTILITIES CORP.

# MANDATE OF THE AUDIT COMMITTEE

By appropriate resolution of the board of directors (the "**Board**") of Algonquin Power & Utilities Corp., the Audit Committee (the "**Committee**") has been established as a standing committee of the Board with the terms of reference set forth below. Unless the context requires otherwise, the term "Corporation" refers to Algonquin Power & Utilities Corp. and its subsidiaries.

## 1 PURPOSE

1.1 The Committee's purpose is to:

(a) assist the Board's oversight of:

(i) the integrity of the Corporation's financial statements, Management's Discussion and Analysis ("**MD&A**") and other financial reporting;

(ii) the Corporation's compliance with legal and regulatory requirements;

(iii) the external auditor's qualifications, independence and performance;

(iv) the performance of the Corporation's internal audit function and internal auditor;

(v) the communication among management of the Corporation and its subsidiary entities and the Corporation's Chief Executive Officer and its Chief Financial Officer (collectively, "**Management**"), the external auditor, the internal auditor and the Board;

(vi) the review and approval of any related party transactions; and

(vii) any other matters as defined by the Board;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

## 2 COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

(a) be a director of the Corporation;

(b) not be an officer or employee of the Corporation or any of the Corporation's subsidiary entities or affiliates;

(c) be an unrelated director for the purposes of the Toronto Stock Exchange (the "**TSX**") Corporate Governance Policy; and

(d) satisfy the independence requirements applicable to members of audit committees under each of the rules of National Instrument 52 110 – Audit Committees of the Canadian Securities Administrators ("**NI 52 110**") and other applicable laws and regulations.

2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under the TSX Corporate Governance Policy, NI 52 110 and other applicable laws and regulations.

2.4 Annual Appointment of Members – The Committee and its Chair shall be appointed annually by the Board and each member of the Committee shall serve at the pleasure of the Board until he or she resigns, is removed or ceases to be a director.

## 3 COMMITTEE MEETINGS

3.1 Time and Place of Meetings – The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly and meetings of the Committee shall be convened whenever requested by the external auditors or any member of the Committee in accordance with the Canada Business Corporations Act. A majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings – As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Board approve, the annual audited financial statements of the Corporation or at which the Committee reviews the interim financial statements of the Corporation, and at such other times as the Committee deems appropriate, the Committee shall meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

(a) representatives of Management;

(b) the external auditor; and

(c) the internal audit personnel.

3.3 Attendance at Meetings – The external auditors are entitled to receive notice of every Committee meeting and to be heard and attend thereat at the Corporation's expense. In addition, the Committee may invite to a meeting any officers or employees of the Corporation, legal counsel, advisor and other persons whose attendance it considers necessary or desirable in order to carry out its responsibilities.

**4 COMMITTEE AUTHORITY AND RESOURCES**

4.1 Direct Channels of Communication – The Committee shall have direct channels of communication with the Corporation's internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Corporation such independent legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.

4.3 Funding – The Corporation shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this mandate.

4.4 Investigations – The Committee shall have unrestricted access to the personnel and documents of the Corporation and the Corporation's subsidiary entities and shall be provided with the resources necessary to carry out its responsibilities.

**5 REMUNERATION OF COMMITTEE MEMBERS**

5.1 Director Fees Only – No member of the Committee may accept, directly or indirectly, fees from the Corporation or any of its subsidiary entities other than remuneration for acting as a director or member of the Committee or any other committee of the Board.

5.2 Other Payments – For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Corporation. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Corporation or any of its subsidiaries, other than limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

**6 DUTIES AND RESPONSIBILITIES OF THE COMMITTEE**

6.1 Overview – The Committee's principal responsibility is one of oversight. Management is responsible for preparing the Corporation's financial statements and the external auditor is responsible for auditing those financial statements.

6.2 The Committee's specific duties and responsibilities are as follows:

(a) Financial and Related Information

(i) Annual Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's annual financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(ii) Interim Financial Statements – The Committee shall review and discuss with Management and the external auditor the Corporation's interim financial statements and related MD&A and if applicable, report thereon to the Board as a whole before they approve such statements and MD&A.

(iii) Prospectuses and Other Documents – The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Board as a whole.

(iv) Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Corporation's accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of

Management's disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management's judgments and accounting estimates and the external auditor's judgments about the quality of the Corporation's accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor's preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Corporation's selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off balance sheet structures, on the financial statements of the Corporation; and

(G) the adequacy of the Corporation's internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information – The Committee shall:

(A) review, and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Corporation containing audited, unaudited or forward-looking financial information in advance of its public release by the Corporation, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, other than the Corporation's financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor

(i) Authority with Respect to External Auditor – As representative of the Corporation's shareholders and as a committee of the Board, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Corporation. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Corporation's shareholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Board and the Committee as representatives of shareholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan – The Committee shall approve, prior to the external auditor's audit, the external auditor's audit plan (including, without limitation, staffing), the scope of the external auditor's review and all related fees.

(iii) Independence – The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Corporation and the Committee shall actively engage in a dialogue with the external auditor with respect to any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Board take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor's independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefor) provided to the Corporation or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor's independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Committee may delegate to one or more designated members of the Committee, such designated members not being members of management, the authority to approve additional non-audit services that arise between Committee meetings, provided that such designated members report any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Corporation's subsidiary entities hiring partners, employees, former partners and former employees of the Corporation's external auditor or former external auditor.

(iv) Rotating of Auditor Partner – The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit – The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Corporation's response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department's responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Corporation's auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters – The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook – Assurance relating to the conduct of the audit.

(c) Internal Audit Function – Controls

(i) Regular Reporting – Internal audit personnel shall report regularly to the Committee.

(ii) Oversight of Internal Controls – The Committee shall oversee Management's design and implementation of and reporting on the Corporation's internal controls and review the adequacy and effectiveness of Management's financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems devisable in respect of the internal audit function.

(iii) Review of Audit Problems – The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management's responses thereto.

(iv) Review of Internal Audit Personnel – The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) Risk Assessment and Risk Management

(i) Risk Exposure – The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Corporation's major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) Investment Practices – The Committee shall review Management's plans and strategies around investment practices, banking performance and treasury risk management.

(iii) Compliance with Covenants – The Committee shall review Management's procedures to ensure compliance by the Corporation with its loan covenants and restrictions, if any.

(e) Legal Compliance

(i) On at least a quarterly basis, the Committee shall review with the Corporation's legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Corporation's financial position, operating results or financial statements and the Corporation's compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Board with respect to the Corporation's policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Board, promptly after becoming aware of any material non-compliance by the Corporation with applicable laws and regulations.

(f) Whistle Blowing – The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Corporation's subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Related Party Transactions– The Committee shall review and approve any transaction between the Corporation and a related party and any transaction involving the Corporation and another party in which the parties' relationship could enable the negotiation of terms on other than an independent, arms' length basis.

(h) Review of the Management's Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Corporation's financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co–operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(j) Public Reports – The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Corporation's public disclosure documents relating to the Committee.

(k) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

## 7 REPORTING TO THE BOARD

7.1 Regular Reporting – If applicable, the Committee shall report to the Board following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

## 8 EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review – The Committee shall periodically assess its performance.

8.2 Amendments to Mandate

(a) Review by Committee – On at least an annual basis, the Committee shall review and discuss the adequacy of this mandate and if applicable, recommend any proposed changes to the Board.

(b) Review by Board – The Board will review and reassess the adequacy of the mandate on an annual basis and at such other times, as it considers appropriate.

## 9 LEGISLATIVE AND REGULATORY CHANGES

9.1 Compliance – It is the Board' intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this mandate shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least annually to reflect such amendments.

## 10 CURRENCY OF MANDATE

10.1 Currency of Mandate – This mandate was approved by the Board of Directors of Algonquin Power & Utilities Corp. effective March 31, 2010.

## GLOSSARY OF TERMS

In this Annual Information Form, the following terms have the meanings set forth below, unless otherwise indicated.

"**ACC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**Acquisition**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**ADEQ**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Principal Markets and Regulatory Environments".*

"**Adjusted EBITDA**" means adjusted earnings before interest, taxes, depreciation and amortization.

"**AESO**" has the meaning ascribed thereto under *"Description of the Business - Description of Operations - Principal Markets and Distribution Methods".*

"**Alberta Power Pool**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Principal Markets and Distribution Methods"*.

"**Ahlstrom ESA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities"*.

"**AIF**" or "**Annual Information Form**" means this annual information form.

"**APCH**" means Algonquin Power (Canada) Holdings Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APCI**" means Algonquin Power Corporation Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group"*.

"**APCo**" means Algonquin Power Co. See *"Corporate Structure - Name, Address and Incorporation"*.

"**APFA**" means Algonquin Power Fund (America) Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APOT**" means Algonquin Power Operating Trust. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Apple Valley**" means Apple Valley Ranchos Water Company, now known as Liberty Utilities (Apple Valley Ranchos Water) Corp.

"**Apple Valley Ranchos Water System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APSC**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

"**APT**" means Algonquin Power Trust. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**APUC**" (or the "Corporation") means Algonquin Power & Utilities Corp including, for reporting purposes only, the direct or indirect subsidiary entities of APUC and partnership interests held by APUC and its subsidiaries. See *"Corporate Structure - Name, Address and Incorporation"*.

"**APUC Businesses**" means the two businesses through which APUC primarily conducts its operations: independent power generation and utilities (water, natural gas and electric).

"**Audit Committee**" has the meaning ascribed thereto under *"Enterprise Risk Management".*

"**Avoided Costs**" means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator.

"**Bakersfield I Solar Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**Bakersfield II Solar Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group"*.

"**Black Mountain System**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**Board**" means the APUC Board of Directors.

"**BRRBA**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**CalPeco**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**CalPeco Electric System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Chaplin Wind Project**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Business Development"*.

"**COD**" means commercial operation date.

"**COG**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Natural Gas Distribution Systems - Material Facilities".*

"**Common Shares**" means the common shares of APUC created pursuant to a certificate and articles of arrangement dated October 27, 2009. See *"Corporate Structure - Name, Address and Incorporation"*.

"**Co-Owners**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**Cornwall Solar**" means Cornwall Solar Inc. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Corporate Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Corporate"*.

"**Côte Ste.-Catherine Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**CPCN**" has the meaning ascribed thereto under *"Description of the Business - Three Year History and Significant Acquisitions - Fiscal 2015 - Transmission Group"*.

"**CPUC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

**"CRCE"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**DBRS**" means the credit rating agency Dominion Bond Rating Service Limited.

"**Debentures**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**Default Service**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Electric Distribution Systems - Material Facilities"*.

"**Deerfield Wind Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2015 - Generation Group"*.

"**Dickson Dam Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**Distribution Credit Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**Distribution Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Donnacona Hydro Facility**" means the Donnacona hydroelectric facility.

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization.

"**ECAC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Electric Distribution Systems - Principal Markets and Regulatory Environments".*

"**Emera**" means Emera Inc. See *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Corporate"*

"**Empire**" means Empire District Electric Company.

"**EnergyNorth Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**EWGs**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**FERC**" has the meaning ascribed thereto under *"Description of the Business - General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Transmission Group".*

"**FIT**" means feed-in tariff.

"**FPA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**FBO**" means funded by others.

"**Final Instalment**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**Final Instalment Date**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**First Instalment**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**GAAP**" means Generally Accepted Accounting Principles.

"**Gamesa**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**Generation Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Generation Credit Facility**" has the meaning ascribed thereto under "*General Development of the Business - Three Year Historical and Significant Acquisitions - Fiscal 2013 - Distribution Group*"

"**Gold Canyon Water System**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**Goldwind**" has the meaning ascribed thereto under "*General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**GPSC**" means Georgia Public Service Commission.

"**GRAM**" means the Georgia Rate Adjustment Mechanism.

"**Great Bay Solar Project**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2015 - Generation Group".*

"**Granite State Electric System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**GW**" means a gigawatt.

"**Hydro Quebec**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**IESO**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**Instalment Receipts**" has the meaning ascribed thereto under "*General Development of the Business - Recent Developments - 2016 - Corporate*".

"**ISO**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes - Power Generation - Canada".*

"**ISO-NE**" has the meaning ascribed thereto under the heading *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Principal Markets and Distribution Methods".*

"**ISRS**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**Kinder Morgan**" means Kinder Morgan, Inc.

"**kV**" means kilovolt.

"**Liberty SubCo**" has the meaning ascribed thereto under *"Corporate Structure - Name, Address and Incorporation".*

"**Liberty Utilities**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Long Sault**" has the meaning ascribed thereto under *"Legal Proceedings and Regulatory Actions - Legal Proceedings - Long Sault Global Adjustment Claim"*.

"**Long Sault Hydro Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**LLC**" means Limited Liability Company.

"**LPSCo System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

"**LS Partnership**" means Algonquin Power (Long Sault) Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**LU Canada**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**LU GP1**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Manitoba Hydro**" means the Manitoba Hydro-Electric Board.

"**Market Path Project**" has the meaning ascribed thereto under "*Description of the Business - Transmission Group - Description of Operations - Natural Gas Pipeline Transmission - Investments*".

"**MBR Authority**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**MD&A**" means the Corporation's management's discussion and analysis.

"**Midstates Gas Systems**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Distribution Business Group".*

"**Minonk Wind Facility**" means the Minonk wind energy facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group"*

"**MMBTU**" means one million British Thermal Units.

**"Mont-Laurier Hydro Facility"** means Mont-Laurier hydroelectric generating facility. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group"*

"**Mont-Laurier Partnership**" means Algonquin Power (Mont-Laurier) Limited Partnership. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**Moody's**" means Moody's Investors Services, Inc.

"**MNPSC**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Principal Markets and Regulatory Environments".*

"**Mountain Water**" means Mountain Water Company.

"**Mountain Water System**" has the meaning ascribed thereto under *"Enterprise Risk Management - Regulatory Climate and Permitting Risk".*

**"MPSC"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

**"MW"** means megawatt.

**"MVA"** means mega-volt ampere.

"**New England Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Distribution Business Group".*

"**NHPUC**" means the New Hampshire Public Utilities Commission. See *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**NERC**" means the North American Electric Reliability Corporation.

"**Northeast Expansion**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Transmission Group".*

"**Northeast Supply**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Northern Maine Gen Co.**" means Algonquin Northern Maine Gen Co., a Wisconsin company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group"*.

"**NV Energy**" means NV Energy, Inc.

"**O&M**" means an operation and maintenance service agreement.

"**OATT**" means open access transmission tariff.

**"Odell Wind Project"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**OEB**" means the Ontario Energy Board.

"**Offering**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016 - Corporate".*

"**OEFC**" means Ontario Electric Financial Corporation.

"**OPA**" means the Ontario Power Authority.

"**Optionee**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Options**" has the meaning ascribed thereto under "*Description of Capital Structure - Stock Option Plan*".

"**Park Water**" means the regulated water distribution utility, Park Water Company, now known as Liberty Utilities (Park Water) Corp.

"**Park Water System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

**"Peach State"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Peach State Gas System**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**PG&E**" means Pacific Gas & Electric Company. See *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

"**PGA**" means Purchased Gas Adjustment.

"**Pine Bluff Water System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Distribution Group".*

"**PJM**" means PJM Interconnection. See *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Principal Markets and Distribution Methods".*

"**PPA**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**PSU**" has the meaning ascribed thereto under "*Description of Capital Structure - Performance Share Units*".

"**PUHCA**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**QFs**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Regulatory Regimes-Power Generation - United States".*

"**Rating Agencies**" means collectively DBRS, and S&P, and "Rating Agency" means one of the Rating Agencies.

"**REC**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Renewable Energy Credits".*

"**Red Lily Wind Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**RES**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Rio Rico System**" has the meaning ascribed thereto under *"Description of the Business - Distribution Group - Description of Operations - Water Distribution and Waste Water Collection Systems - Material Facilities".*

"**RPS**" means renewable portfolio standards.

"**S&P**" means Standard & Poor's Financial Services LLC.

"**Sandy Ridge Wind Facility**" means the Sandy Ridge wind energy facility.

"**Sanger LLC**" means Algonquin Power Sanger LLC, a California limited liability company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**Sanger Thermal Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**SaskPower**" means Saskatchewan Power Corporation.

"**Senate Wind Facility**" means the Senate wind energy facility.

**"Series 3 Debentures"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Corporate".*

"**Series A Shares**" has the meaning ascribed thereto under "*Dividends - Preferred Shares".*

"**Series C Shares**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

**"Series D Shares"** has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Corporate".*

"**Shady Oaks Wind Facility**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Generation Group".*

**"Squa Pan Hydro Facility"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**St. Alban Hydro Facility**" means the St. Alban hydroelectric generating facility.

"**Ste. Brigitte Hydro Facility**" means the St. Brigitte hydroelectric generating facility.

"**St. Leon II Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon GP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**St. Leon LP**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

"**St. Leon Wind Facility**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

**"Strategic Investment Agreement"** has the meaning ascribed thereto under the heading *"Description of Capital Structure - Private Placement of Subscription Receipts and Common Shares to Emera".*

"**Subscription Receipts**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2013 - Corporate".*

"**Supply Path Project**" has the meaning ascribed thereto under *"Description of the Business - Transmission Group - Description of Operations - Natural Gas Pipeline Transmission - Investments".*

"**Tinker Hydro Facility**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Hydroelectric Generating Facilities - Material Facilities".*

"**Transmission Group**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**TSX**" means the Toronto Stock Exchange.

**"Unit Exchange Transaction"** has the meaning ascribed thereto under *"Enterprise Risk Management - Financial Risk Management - Tax Risk and Uncertainty".*

"**Underwriters**" has the meaning ascribed thereto under *"General Development of the Business - Recent Developments - 2016".*

"**U.S. Wind Portfolio**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Generation Group".*

"**Val-Éo Wind Project**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries".*

"**Vestas**" has the meaning ascribed thereto under *"Description of the Business - Generation Group - Description of Operations - Wind Power Generating Facilities - Material Facilities".*

"**Windlectric**" has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries"*.

"**Windsor LLC**" means Algonquin Power Windsor Locks LLC, a Connecticut limited liability company. See *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*

**"Windsor Locks Thermal Facility"** has the meaning ascribed thereto under the heading *"Description of the Business - Generation Group - Description of Operations - Thermal (Cogeneration) Electric Generating Facilities - Material Facilities".*

"**White Hall Water System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

"**White Hall Waste System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

"**White Hall Water and Waste System**" has the meaning ascribed thereto under *"General Development of the Business - Three Year History and Significant Acquisitions - Fiscal 2014 - Distribution Group".*

**"WP SponsorCo"** has the meaning ascribed thereto under *"Corporate Structure - Intercorporate Relationships - Subsidiaries - Generation Business Group".*